ERCB Energy Resources Conservation Board
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Directive 065

Revised edition April 1, 2010
Effective April 1, 2010
This edition incorporates changes noted in "What's New," page 6.

Resources Applications for Conventional Oil and Gas Reservoirs

The Energy Resources Conservation Board (ERCB/Board) has approved this directive on April 1, 2010.

Dan McFadyen
Chairman

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How to Use This Directive

Directive 065 simplifies the process to apply to the Energy Resources Conservation Board (ERCB) for all necessary approvals to establish the strategy and plan to deplete a pool or portion of a pool using one resource application. Previously, the requirements were mainly found in Part 15 of the *Oil and Gas Conservation Regulations*.

This directive also enables you to review in a single document the application requirements and the explanations for those requirements for most conventional oil and gas reservoir topics considered in an application for ERCB approval. "Must" indicates a requirement for which compliance is required and is subject to ERCB enforcement, while "recommends" indicates a best practice that can be used but is not an ERCB requirement and does not carry an enforcement consequence. The ERCB will conduct periodic reviews of this directive's continued usefulness for applicants and conduct updates based on feedback received and re-engineering reviews.

The modifications and new requirements in the April 2010 edition were effective April 1, 2010.

Introduction

Specific resource applications are required to allow the ERCB and potentially affected parties, often with competing interests, to understand and test the appropriateness or impact of depletion plans at critical milestones. Other resource applications may address revisions to the baseline set of depletion or equity rules and reservoir descriptions. Finally, some resource applications address known equity disputes arising from different ownership, limited opportunity to produce, or access constraints to established facilities. If such issues are not resolved, these applications go directly to a hearing.

The ERCB reviews all resource applications to ensure that the appropriate level of reservoir engineering and geological science is applied in managing poolwide depletion and that potential impacts on other stakeholders are identified and dealt with fairly. Because individual reservoirs are unique, detailed assessments may be necessary to ensure that the depletion plan is appropriate and recovery is in the public interest. You must provide sufficient up-front information and analysis to support the reasonableness of your proposals.

The ERCB has compiled this comprehensive directive to support a level playing field for all applicants. Applicants are expected to know and understand requirements and file accurate and complete applications. ERCB staff will not complete missing application requirements, such as raw data collection and supporting analytical discussion. Instead, ERCB staff will test assumptions, check completeness and accuracy of data and assessments, and test alternatives.

What This Directive Contains

This directive includes Schedule 1: Resources Applications registration form, guidelines on notification requirements, and seven units that address detailed information requirements for specific regulatory topics, as well as appendices giving reference sources and other support information.

Applicants must prepare the following resources applications using *Directive 065*. A Schedule 1 form must accompany these applications to provide the ERCB with key information about the applicant, the type of application, the area of application, and details of notice to potentially affected parties undertaken by the applicant.

The resources applications for which this directive applies are divided into units as follows:

1) **Equity**: rateable take, common purchaser, common carrier, common processor, and compulsory pooling
2) **Conservation**: enhanced recovery scheme (gas cycling, waterflood, immiscible gas flood, miscible flood), concurrent production, and pool delineation and ultimate reserves
3) **Production Control**: commingled production, good production practice (primary depletion pools), gas-oil ratio penalty relief, special maximum rate limitation, and gas allowable
4) **Disposal/Storage**: disposal (water and waste), acid gas disposal, and underground gas storage
5) **Corporate Changes**: change in name of the holder of an ERCB approval and change in holder of an ERCB approval
6) **Gas and Ethane Removal**: short and long-term natural gas removal, short-term ethane removal.
7) **Special Well Spacing**: holdings, reduced drilling spacing units, change in target area, rescinding a holding, and change in approval holder.

The appendices include

- list of references
- notification templates
- Application for Gas-Oil Ratio Penalty Relief (Form O-33)
- Transfer of Approval form
- list of ERCB contacts
- Enhanced Recovery Scheme application form
- gas and ethane removal application forms
- Gas Reserves Data Sheet
- Special Well Spacing applications forms
- Special Well Spacing attachment examples

You are strongly encouraged to become familiar with the references listed in Appendix A before completing your applications.

What's New in *Directive 065*

Effective April 1, 2010, all resources applications contained in *Directive 065* must be submitted electronically through the Digital Data Submission (DDS) on the ERCB Web site www.ercb.ca and will no longer be accepted on paper.

Further, the April 2010 edition of *Directive 065* incorporates changes to Unit 7 which were announced in *ERCB Bulletin 2010-07* to reflect:

- amendments to Part 4 of the *Oil and Gas Conservation Regulations*, and
- changes to notification requirements.

All other sections remain unchanged as in the October 2009 edition.

Procedure for Reviewing Application

Figure 1 shows the overall oil and gas resources applications process, Figure 2 shows the oil and gas resources applications evaluation process, and Figure 3 shows well spacing applications evaluation.

Step 1: Application Registration

All resources applications contained in this directive must be submitted electronically through DDS on the ERCB Web site www.ercb.ca. The ERCB assigns each application package a unique application number. Applicants are encouraged to confirm the registration and contact information of their application by checking the Integrated Application Registry (IAR), accessible from the Applications page on the ERCB's Web site www.ercb.ca.

Note that all data must be submitted using metric units (SI).

Step 2: Corporate Record Check

All applications are subject to a corporate check to verify acceptable performance records and other information in ERCB files.

Applicants seeking formal approval must hold a valid company code issued by the ERCB's Corporate Compliance Group. If you are a first-time applicant, you must obtain a company code by filing a corporate profile with the ERCB's Corporate Compliance Group. Information packages are available from the Corporate Compliance Group at (403) 297-8320. You must update your corporate profile when asked to do so by the ERCB.

ERCB approvals identify the applicant as the holder of the approval, and this party is responsible and accountable for compliance with all regulations and the approval conditions. Applicants requesting changes to a general order of the ERCB, reservoir description, and operational practices not requiring a change to an approval do not need to have a company code but must have a valid interest in the pool.

If you are on "refer" status due to an unresolved serious noncompliance problem, the ERCB may ask additional questions, including questions related to corporate accountability, technical competency, and corporate commitment to compliance with provincial standards, as part of the ERCB enforcement policy detailed in *Directive 019: ERCB Compliance Assurance—Enforcement*. In the case of a "refer" status, ERCB Board members are directly involved in the consideration of any application, which may include a decision to go to a hearing. Otherwise, the application is normally reviewed and, if appropriate, approved by the delegated work groups within the ERCB.

Step 3: Application Returned or Delayed if Incomplete

Effective October 1, 2000, the ERCB will no longer process an application identified in this directive if it is substantially incomplete (i.e., has a major deficiency). It will be returned to you with an explanation. An example of such a major deficiency is the complete omission of an entire key information segment of any unit requirements, such as the geological description. If the application has minor deficiencies, such as lacking specific information needed to make a decision, you will be provided with a clear explanation and given 5 working days to respond. Failure to respond in this time frame will result in the ERCB closing and returning your application with written notification of the reason. The ERCB is prepared to correct small errors in the submitted information, as long as applicants show improvement in submitting better-quality applications.

Note that if the ERCB returns a severely deficient and incomplete application that you filed in response to an ERCB request, such as for improvement in recovery or operational performance, you will be subject to any consequences or penalties previously identified at the time of the request.

Step 4: Application Evaluation

This directive identifies some circumstances that may reduce application requirements and, in turn, result in a faster decision on the application. You may want to consider the long-term benefits of creating some of these circumstances, such as equity agreements and poolwide plans, before you file a competitive, partial pool application.

The evaluation of your application may also be expedited if your definition of the pool extent is consistent with the ERCB's pool designation or you provide a discussion on any variances. Resolving significant differences, such as pool delineation, once the application is filed could add considerable time to the application process and raise issues that are better dealt with beforehand.

When evaluating an application, the ERCB reviews a pool's unique features, if any, to assess whether additional information, analysis, or consultation beyond what is identified in the directive is required. As explained in the Resources Applications Notification Guidelines and individual units of this guide, in those cases where the applicant has chosen to conduct notification the ERCB will require submission of documentation describing your notification program. The ERCB will review this evidence, especially the written notice or other correspondence, showing that you have contacted all potentially affected parties and provided them with a fair opportunity to learn about your planned application and to submit their views to you and the ERCB. Signed letters of nonobjection are preferred in this regard, but the ERCB will also consider other evidence and explanations of your efforts to address notification within a reasonable time period.

Objections/Dispute Resolution

The ERCB expects applicants to conscientiously address all relevant concerns raised by potentially adversely affected parties. Should disputes arise, the ERCB expects the parties to discuss the issues and options for resolution, including the use of third-party mediators. ERCB staff, if requested, can assist in explaining ERCB rules and in facilitation.

If you conclude that further discussion is unlikely to resolve issues, you should inform the ERCB, outlining concerns, steps you have taken to resolve problems, and your recommended course of action. Note that outstanding objections can result in an ERCB hearing. Should a hearing be called, both you and the intervener might be asked to file additional substantiating evidence. Matters of confidentiality and disclosure should be addressed and determined by the parties prior to submission of the evidence.

Documented Decisions/Compliance

ERCB decisions on the resource applications listed in this directive are issued in written format and generally include a letter and either a formal site-specific approval or a regional or provincial order.

ERCB requirements for resource activities covered by *Directive 065* are set out in the *Oil and Gas Conservation Act*, *Oil and Gas Conservation Regulations*, this directive, and conditions of approval. These are the requirements that you have a legal obligation to meet and against which the ERCB may take enforcement action in cases of noncompliance.

You must not assume that an approval has or will be granted just because an application has been submitted.

If an unauthorized activity occurs or if conditions of approval are not met, enforcement action will be taken in accordance with *Directive 019*. Immediate corrective action, such as the shut-in of well operations, is required. See specific sections of *Directive 065* for details of compliance requirements and enforcement action.

The enforcement process is explained in *Directive 019*, and a list of risk-assessed noncompliance events and associated compliance categories are listed on the ERCB Web site www.ercb.ca under ERCB Home : Industry Zone : Compliance and Enforcement : Risk Assessed Noncompliance.

Voluntary Self-Disclosure

Licensees are encouraged to actively monitor compliance using tools such as surveillance and audits. Rules for voluntary self-disclosure and a list of events that are not considered self-disclosure are listed in *Directive 019*. Send self-disclosure information to

E-mail: ResourceCompliance@ercb.ca
Fax: 403-297-8122
Mail: Energy Resources Conservation Board
Resources Applications, Enforcement and Surveillance Section
640 – 5 Avenue SW
Calgary, Alberta T2P 3G4

Figure 1. Resources Applications Process

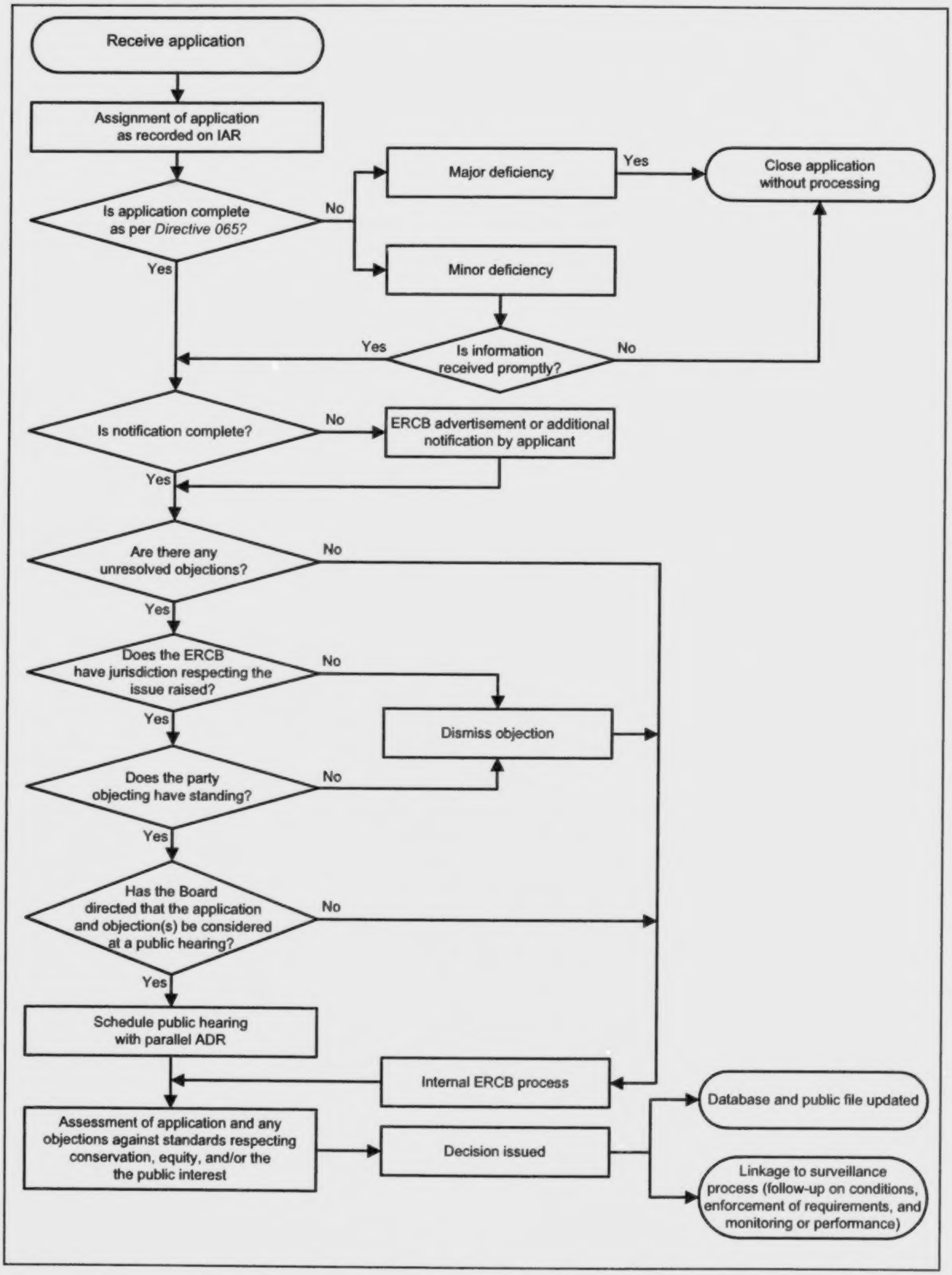

Receive application
Assignment of application as recorded on IAR
Is application complete as per *Directive 065?*
No
Major deficiency
Yes
Close application without processing
Minor deficiency
Yes
Is information received promptly?
Yes
No
Is notification complete?
No
ERCB advertisement or additional notification by applicant
Yes
Are there any unresolved objections?
No
Yes
Does the ERCB have jurisdiction respecting the issue raised?
No
Yes
Dismiss objection
Does the party objecting have standing?
No
Yes
Has the Board directed that the application and objection(s) be considered at a public hearing?
No
Yes
Schedule public hearing with parallel ADR
Internal ERCB process
Assessment of application and any objections against standards respecting conservation, equity, and/or the the public interest
Decision issued
Database and public file updated
Linkage to surveillance process (follow-up on conditions, enforcement of requirements, and monitoring or performance)

Figure 2. Resources Applications Evaluation

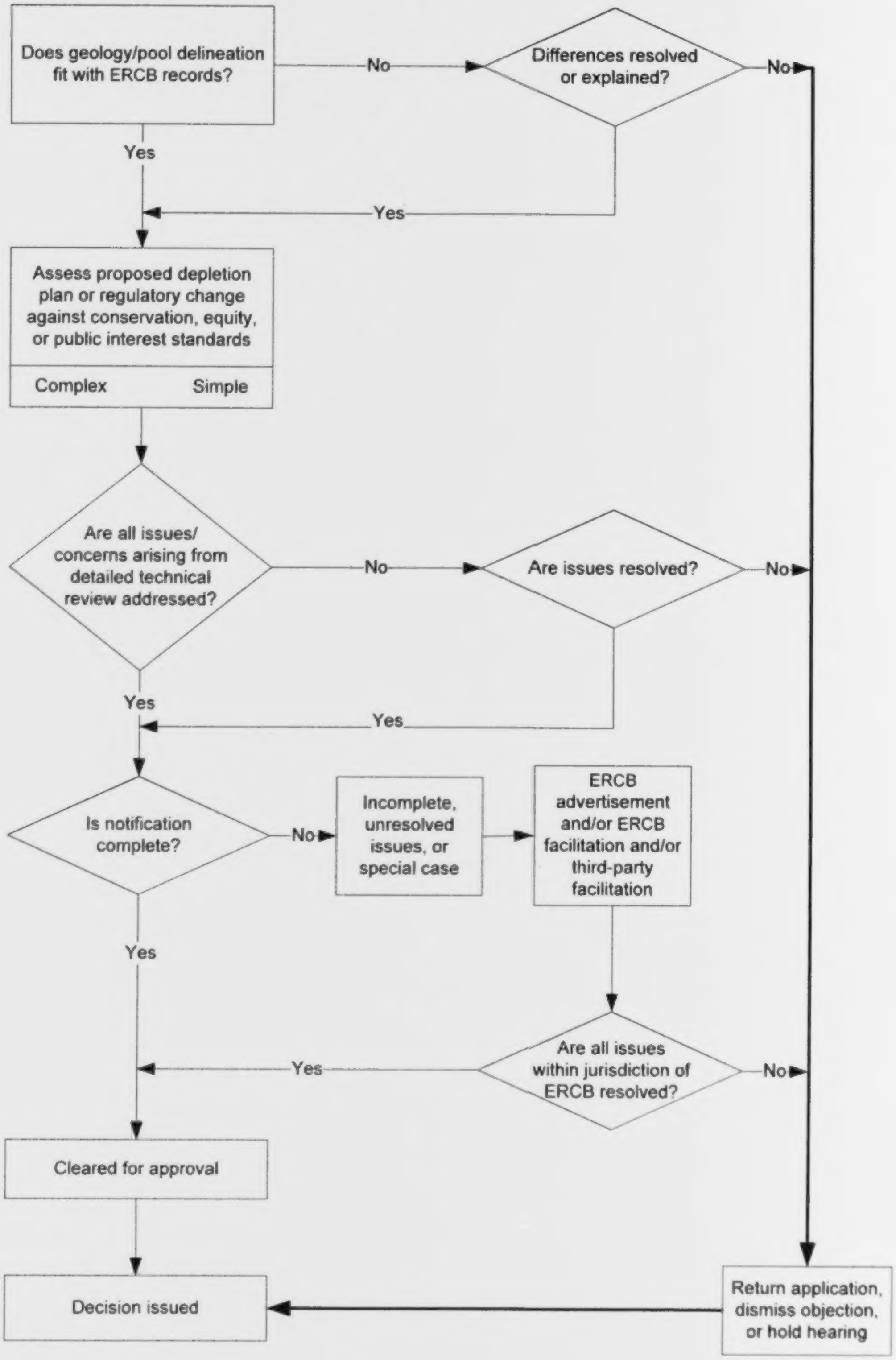
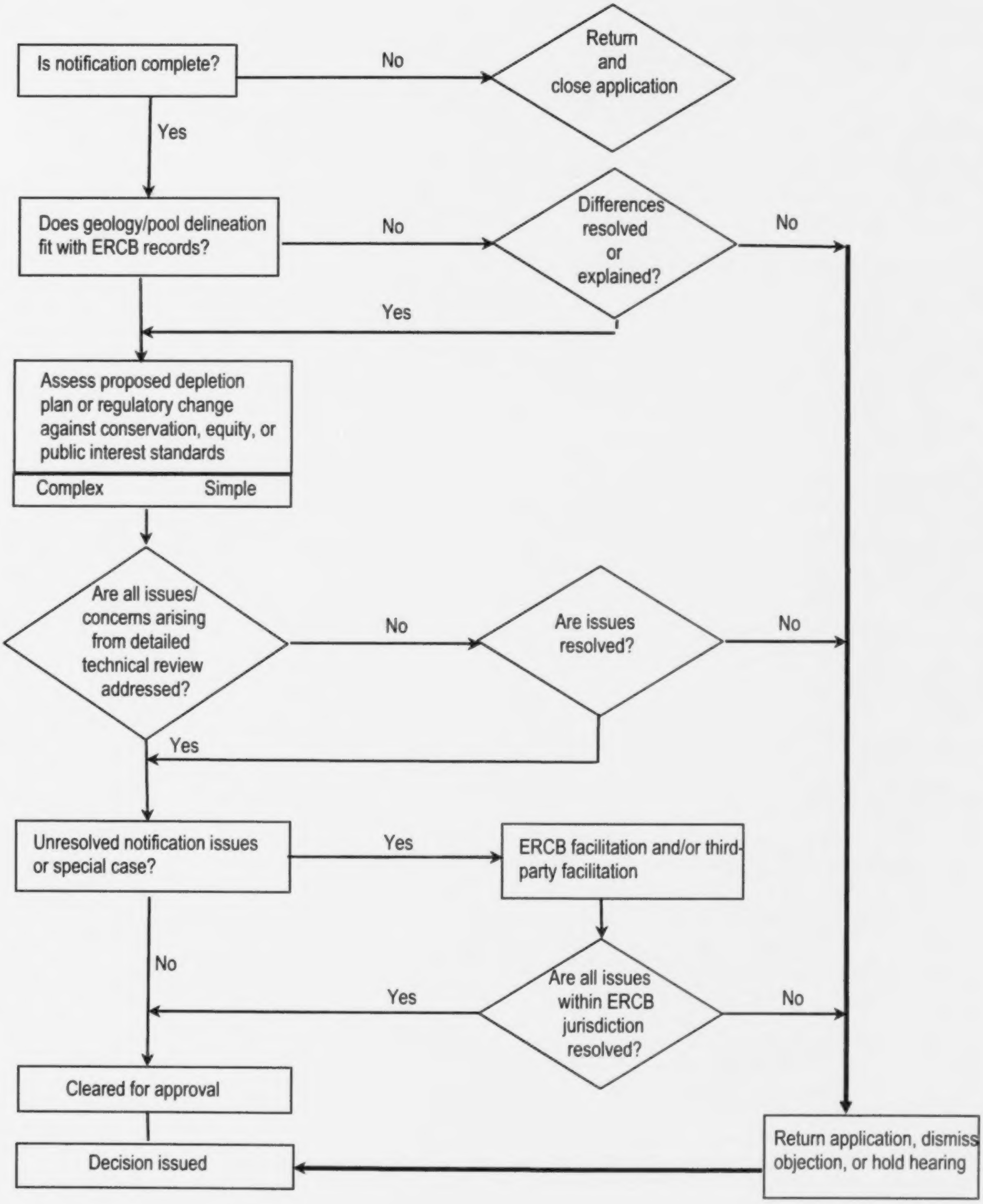

Does geology/pool delineation fit with ERCB records?
No
Differences resolved or explained?
No
Yes
Yes
Assess proposed depletion plan or regulatory change against conservation, equity, or public interest standards
Complex
Simple
Are all issues/ concerns arising from detailed technical review addressed?
No
Are issues resolved?
No
Yes
Yes
Is notification complete?
No
Incomplete, unresolved issues, or special case
ERCB advertisement and/or ERCB facilitation and/or third-party facilitation
Yes
Are all issues within jurisdiction of ERCB resolved?
Yes
No
Cleared for approval
Decision issued
Return application, dismiss objection, or hold hearing

Figure 3. Well Spacing Applications Evaluation



Is notification complete?
No
Return and close application
Yes
Does geology/pool delineation fit with ERCB records?
No
Differences resolved or explained?
No
Yes
Assess proposed depletion plan or regulatory change against conservation, equity, or public interest standards
Complex
Simple
Are all issues/ concerns arising from detailed technical review addressed?
No
Are issues resolved?
No
Yes
Unresolved notification issues or special case?
Yes
ERCB facilitation and/or third-party facilitation
No
Yes
Are all issues within ERCB jurisdiction resolved?
No
Cleared for approval
Decision issued
Return application, dismiss objection, or hold hearing

Schedule [illegible]

ERCB Energy Resources Conservation Board

Resources Applications - Schedule 1

Applicant General Information

DAY MONTH YEAR ____________ APPLICATION # ________ APPLICANT'S FILE NUMBER ____________

The applicant certifies that the information provided here and in all supporting documentation is correct and in accordance with all regulatory requirements or as directed by the Energy Resources Conservation Board.

SUBMISSION STATUS ____________ SUBMISSION ID ________ CREATION DATE ________

1. APPLICANT INFORMATION

COMPANY NAME ____________ BA CODE ________
CONTACT NAME ____________
TELEPHONE ________ FAX ________
E-MAIL ____________
MAILING ADDRESS ____________

2. APPLICATION TYPE

(For Electronic Submission purposes, Resources Applications only accepts one application type per submission)

APPLICATION DESCRIPTION

3. LOCATION (Minimum input Twp/Rg/Mer)

LE	Lsd	Sec	Twp	Rge	Mer	ES	LE	Lsd	Sec	Twp	Rge	Mer	ES
					W							W	
					W							W	
					W							W	
					W							W	
					W							W	

4. FIELD AND POOL LIST

Field Name	Pool Name
-	-

5. OWNERSHIP AND NOTIFICATION INFORMATION

1. What is the ownership basis on which you make this application?

2. Has notification been conducted in accordance with the requirements for this application? Yes ☐ No ☐

2a. If no, do you need ERCB assistance to complete the notification requirements? Please explain. Yes ☐ No ☐

3. Are there outstanding concerns? Yes (please explain) Yes ☐ No ☐

SUBMISSION STATUS ____________ SUBMISSION ID ________ CREATION DATE ________

6. FUTURE APPLICATIONS

1. Have you, or do you plan to submit additional Resources Applications associated with the present application to the ERCB? Yes ☐ No ☐

1a. If yes, state the type of applications or the application numbers (if known):

Application Type	Application Number (If applicable)

If you have any questions or comments, please contact the EAS Administrator.

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Resources Applications Notification Guidelines

When to Notify

Effective notification and consultation programs are critical not only to ensure an efficient regulatory process but to promote long-term relationships. The ERCB prefers, and requires for some resource application types, that both industry and public (where required) notification be completed prior to the filing of the applications.

Whom to Notify

Minimum notification requirements for specific types of resources applications are included in Tables 1 and 2 of this section. In addition to meeting the minimum notification requirements, the ERCB expects you to review your situation and consider whether there are potentially directly and adversely affected parties outside the minimum notification areas and, if so, also provide notification to these parties.

In some cases, the ERCB requires notification for informational purposes only. This type of notification provides information regarding a potential development to support, promote, and encourage early and ongoing discussions between persons.

How to Conduct Notification

Notification is the first step in providing information and is usually conducted through written correspondence, while consultation must occur face to face or by telephone. Early, proactive notification programs are more likely to result in positive relationships. To this end, the ERCB believes that newspaper advertisement does not meet these objectives and should only be used to supplement direct notification in extenuating circumstances. If you know there will be contentious or complex issues respecting a resources application, personal consultation may be preferable as a first step rather than notification. Notification programs that do not provide for direct notice to a person should be discussed with the ERCB prior to conducting the program.

You should provide notification of a proposed application by means of a letter that includes adequate information to allow persons to understand the proposed development and the impact it may have on them. Formats for notification letters are included in Appendix B (for well spacing notification templates, see Appendix J). Notification must take into consideration whether the person being notified is an oil and gas company, a Freehold mineral owner, or a landowner or occupant. You must include applicant contact information in the notification letter, as well as directions about what action persons should take if there is a concern. In all cases, persons should be directed to submit any concerns directly to the applicant, not to the ERCB.

In providing notification, you must take possible delays in delivery of the notification package into consideration. Each person notified must be given a minimum of 15 working days from the date the letter is mailed to respond. A signed letter of consent or nonobjection to the proposal is not required. However, it should be clear in the letter that if the person notified does not respond to the notification package, filing (if not filed) and processing of the application with the ERCB will proceed without further contact.

Consequences of Incomplete Notification

Generally, ERCB staff follow the requirements of each application unit to determine whether a notification program meets the requirements of Section 26 of the *Energy Resources Conservation Act* (*ERCA*). This section requires the ERCB to ensure that all potentially directly and adversely affected persons are given notice of an application and have a reasonable opportunity to make representations to the ERCB regarding the application.

For some application types, the ERCB requires that you provide a description of your notification program and documented evidence of the results in your application, including a list of the persons notified and a copy of the notification letter.

The ERCB will review your notification information to ensure that you have met the requirements in this directive. Should it be determined that inadequate notification was provided or that not all potentially directly and adversely affected persons were notified, the application in most cases will be **closed**.

If an application has been approved, an affected person who was not notified may file an application for review under Section 39 or 40 of the *ERCA* requesting that the approval be reviewed. If the ERCB grants the review application, a hearing will be scheduled. The approval may be suspended pending the outcome of the review.

Responding to Concerns Raised During the Notification Process

The ERCB expects applicants to engage in meaningful discussions with any person who has raised concerns or has questions respecting a proposed application. It is expected that applicants will make substantial efforts to resolve the matter prior to filing and during the review of a resources application, including use of third-party mediators, as discussed in the ERCB's Appropriate Dispute Resolution (ADR) program described in ERCB *Informational Letter (IL) 2001-01*.

If an applicant has made no attempt to respond to a person who has expressed concerns or is seeking understanding or answers to questions, the application, in most cases, will be **closed**.

The ERCB recognizes that discussions may come to an impasse or that a person who has expressed concerns may decline to participate in the ADR process. Additionally, in some cases, a company may be of the view that the objection is not relevant to the issues of the application and that beyond initial efforts it should not be required to attempt to resolve the issue. In these cases, the company may proceed to file its application (if not filed) and to include the letter(s) objecting to the proposal, its response to the objection(s), and a discussion of its view of how the ERCB should proceed with the application.

Table 1. Minimum notification requirements required prior to filing application[1]

Application type (section in *Directive 065*)	**Notification and confirmation of nonobjection from representative list as necessary to ensure coverage**	**Area of contact**
Special well spacing (Unit 7)	• Refer to Unit 7 for notification requirements	
EOR scheme (amendment) (2.1)	• All well licensees of wells completed in the pool	The applied-for approval area and the area within 800 m of any proposed enhanced oil recovery injector
EOR scheme (new) (2.1)	• All well licensees of wells completed in the pool	The applied-for approval area and the area within a quarter section of the applied-for approval area
Gas cycling scheme (amendment)	• All well licensees of wells completed in the pool	The applied-for approval area
Gas cycling scheme (new)	• All well licensees	The applied-for approval area and the area within one section of the applied-for approval area
Concurrent production (2.4)	• Unit operator (if applicable) • Approval holder of scheme (if applicable) • All well licensees	ERCB-designated pool
Waste disposal (Class I)[2] (4.1)	Industry • Unit operator (if applicable) • Approval holder of scheme • All well licensees • All mineral lessees • All mineral lessors	A radius of 1.6 km from the proposed disposal well where the disposal zone is known to be present
	Public • Landowners and occupants	A radius of 0.5 km from the proposed disposal well
Acid gas disposal[3] (4.2)	• Unit operator (if applicable) • Approval holder of scheme (if applicable) • All well licensees • All mineral lessees • All mineral lessors	If into a depleted hydrocarbon pool, the ERCB-designated pool; if into an aquifer, a radius of 1.6 km from the section containing the disposal well
Application type	**Consultation and documentation of negotiations with**	**Area of contact**
Rateable take (1.1)	• All well licensees	ERCB-designated pool if present; otherwise applicant's pool interpretation
Common carrier/processor/ purchaser (1.2, 1.3, 1.4)	• Carrier, processors, or purchasers involved • All well licensees	Not applicable In pool
Compulsory pooling (1.5)	• All mineral lessees • All mineral lessors of unleased tracts	ERCB-designated drilling spacing unit

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[1] Note that these are **minimum** requirements. The consequences of incomplete notification are discussed in the preceding text.

[2] Notification and consent will be required as part of any request for a surface facility approval associated with waste disposal. A surface facility approval must be obtained from the ERCB's Waste Operations Group and/or Alberta Environment before a waste disposal well approval can be issued.

[3] If a new emergency response plan (ERP) is needed or an existing ERP is updated, conduct notification for ERP purposes to all potentially adversely affected parties and provide confirmation of no objection or concerns.

Table 2. Minimum notification requirements required prior to ERCB decision[1]

Application type (section in *Directive 065*)	**Notification and confirmation of nonobjection from representative list as necessary to ensure coverage**	**Area of contact**
Project and enhanced recovery recognition status (2.2/2.3)	• Not applicable	Not applicable
Commingled production (3.1)	• Refer to Section 3.1 for notification requirements	
Good production practice/ special maximum limitation/gas-oil ratio penalty relief (3.2.2, 3.2.3, 3.2.4)	• Unit operator (if applicable) • Approval holder of scheme (if applicable) • All well licensees	ERCB-designated pool
Gas allowable (3.3)	• Unit operator (if applicable) • Approval holder of scheme (if applicable) • All well licensees	ERCB-designated pool plus 1600 m surrounding the pool
Disposal, except waste disposal (Class I) and acid gas disposal (see Table 1) (4.1)	• Unit operator (if applicable) • Approval holder of scheme (if applicable) • All well licensees	A radius of 1.6 km from the proposed disposal well where the proposed disposal zone is known to be present
Underground gas storage[3] (4.3)	• Unit operator (if applicable) • Approval holder of scheme (if applicable) • All well licensees • All mineral lessees • All mineral lessors	The ERCB-designated pool boundary of the proposed storage pool and a 1.6 km radius from that pool boundary; notification should cover all zones, including those that overlie and underlie the storage pool

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[1] Note that these are **minimum** requirements. The consequences of incomplete notification are discussed in the preceding text.

1. Equity

Unit 1 Equity

1.1 Application for a Rateable Take Order

1.1.1 Background

The purposes of the *Oil and Gas Conservation Act* (*OGCA*) are, among other things, to effect the conservation of oil and gas resources, to afford each owner the opportunity of obtaining its share of the production of oil or gas from any pool, and to provide for economic, orderly, and efficient development in the public interest. Section 36 of the *OGCA* mandates the ERCB to address all three of these purposes. Historically this legislation has been used only in the equity context and to allow for economic, orderly, and efficient development; other sections of the *OGCA* have been used to ensure conservation of resources.

Under Section 36 the ERCB may limit the amount of gas that may be produced and/or distribute the amount of gas that may be produced from a pool or part of a pool. Historically, this legislation has been used to authorize the distribution of gas production among wells in a nonassociated gas pool.

1.1.2 When to Make This Application

A situation that could warrant an application under Section 36 of the *OGCA* would typically involve a number of gas wells of different ownership in a pool being on production. One owner believes its reserves are being inequitably drained because its well has been placed on production at rates that do not allow the well to capture the owner's share of the pool reserves. The well's rate may be restricted by pipeline or processing capacity or by a gas sales contract.

In the case where the rate limitation is due to pipeline or processing capacity, the owner has capacity or its own facilities and believes that it would not represent economic, orderly, and efficient development to build or obtain additional capacity. Where the limitation is due to a gas sales contract, the owner has been unable to adjust the contract or produce gas in excess of the contract to allow for an equitable rate of production.

1.1.3 How the ERCB Processes the Application

The ERCB considers the issuance of a rateable take order to be a very significant action because it has the potential to override contractual arrangements put in place through normal business practices. Consequently, before approving an application, the ERCB requires an applicant to demonstrate that it is being deprived of the opportunity to obtain its share of production from the pool. The applicant must show that drainage has occurred and continues to occur or that it can be expected to occur with a very high degree of certainty. Additionally, the drainage must be a result of the applicant not having an opportunity to produce its share of production. The restriction in rate must not be due to limitation in well capability. The ERCB has previously ruled that where the only limitation on production is well capability, a producer is not being deprived of an opportunity to obtain an equitable share of production (*Decision 85-5).*

Each application for a rateable take order proceeds to a public hearing.

1.1.4 Requirements for an Application for a Rateable Take Order (file 12 copies)

Requirements	Comments
1) A statement of what is being requested, including a) a reference that the application is being made under Section 36 of the *OGCA*, and b) the pool and wells to which the order would apply.	For example, HP Gas Company applies for an order under Section 36 of the *OGCA* distributing gas production among wells in the Woodword Viking A Pool, which includes the wells with the unique identifiers of …
2) A discussion giving the reasons why you are requesting the order, including a description of the circumstances that in your opinion have led or will lead to an inequitable situation.	
3) Documentation showing your attempts to negotiate a solution to the problem, including a) identification of all parties involved and the nature of their issues and concerns, and b) an outline of the attempts to resolve the issues, including type of discussions held, timing, and frequency.	You must have made substantial efforts to resolve the situation; the application should be a final resort. You should also continue your efforts to resolve the matter on a voluntary basis (including consideration of a third-party mediator) after the application has been filed with the ERCB. Your discussion must include why the negotiations did not lead to a settlement and what dispute resolution efforts were conducted. Matters of confidentiality and disclosure should be addressed and determined by the parties prior to submission of the application.
4) Your geological interpretation of the pool involved, including a) a net pay isopach map of the pool, including both oil and gas if there is an associated pool, b) an interpreted and annotated log cross-section or representative well log(s) showing i) stratigraphic interpretation of the zone(s) of interest,	This information should show that your well is part of the subject pool. The net pay map should show the entire pool and illustrate wells outside the pool that control the edges of the pool. If there is a dispute among the parties involved regarding the delineation of the pool(s) in question, an annotated cross-section should be included in the application; if there is no dispute respecting this issue, an annotated representative well log is sufficient for the purposes of the application.

Requirements	Comments
ii) interpretation of fluid interfaces present,	
iii) completions and treatments to the wellbore(s), with dates,	
iv) cumulative production,	
v) finished drilling date and kelly bushing (KB) elevation, and	
vi) the scale of the log readings, and	
c) a tabulation of the interpreted net pay, porosity, and water saturation for each well in the pool, along with the cutoffs, methodology, formulas, and constants used.	This allows the ERCB to assess your mapping and reserves calculation requested in the following item. In addition, these data may be used to allocate production (see item 8 below).
5) An evaluation of the oil and gas reserves for the pool and for your lands, including	The reserves estimates confirm that there are reserves available for production.
a) an estimate of the initial oil volume and gas volume in place,	
b) an estimate of the oil and gas recovery factors,	
c) a description of the methods used in determining (a) and (b) above (e.g., material balance, volumetric analysis, model study, a comparison of analog pools), and	
d) the supporting data used in determining (a) and (b) above and the sources of the data (i.e., pressure/volume/temperature (PVT) properties and source, pressure data and source).	All data used in obtaining the reserves estimates should be provided so that your analysis can be duplicated using information supplied in this application.
6) Deliverability test data showing that your well is capable of producing at an economic rate from the pool to which the proposed order would apply.	A summary of the deliverability test data may be used provided the detailed test data have been filed in accordance with ERCB *Directive 040*.

Requirements	Comments
7) Where drainage is alleged, a discussion including a) evidence showing that the reserves underlying your lands have been drained subsequent to the completion of your well in the pool, and b) an estimate of the total amount of inequitable drainage that has occurred from your lands since your well was completed in the pool, together with details of how the drainage was calculated.	In cases where a well has remained shut in, drainage may be confirmed by summarizing at least two pressure tests taken on the well. If you are arguing that your currently producing well is not producing at sufficient rates to recover an equitable share of production, a comparison may be made between the actual produced volume from the well and the volume the well should have produced to obtain an equitable share of production. You should present a detailed calculation showing how you determined your equitable share of production.
8) A discussion of your proposal as to how the ERCB should restrict or distribute production from the pool that includes a) a tabulation of the proportion of production or rate of production that each well or group of wells should be allowed to produce, together with the details of how the proposed production scheme was obtained, and b) if considered appropriate, the total production rate proposed for the pool, together with the details of how this rate was determined and why such a rate should be set, and c) if specific rates are proposed under item 8(a), i) an indication of why rates, rather than a percentage allocation, are being proposed, ii) whether the proposed rates are economic for each well or group of wells, and iii) whether each well or group of wells would be capable of producing at the proposed rate.	The ERCB usually distributes production among wells in a pool on a percentage basis, rather than setting any specific rate or volume. The proportion of production allocated to each well is commonly based on the following formula: *Percentage of pool production for specific well = 100 x (wellbore net pay x porosity x gas saturation x area of spacing unit or validated area for specific well)/(sum of wellbore net pay x porosity x gas saturation x area of spacing units or validated areas for all wells)* *Directive 032* and *Decision 91-8* discuss the ERCB's commonly used allocation formula and the validated area concept. The ERCB has not commonly used mapping as a means to determine hydrocarbon pore volume in a spacing unit because in many cases such mapping is highly interpretative. The ERCB has not normally factored the deliverability of a well into an allocation formula to avoid disputes on what constitutes appropriate well testing. You may propose an allocation formula other than the commonly used one; however, you should include detailed justification as to why the ERCB should deviate from its usual practice in determining an allocation formula.

Requirements	Comments
	It is not usually necessary to limit the total rate of production (item 8(b)), but this remains an option. In respect of item 8(c), it is not the ERCB's usual practice to set specific rates, but this also remains an option. In some cases it may be useful to set minimum rates, with a percentage allocation above the minimum rate. If a well falls below the minimum rate, other wells are restricted only to their minimum rates and not below. Items 8(c)(ii) and 8(c)(iii) should be addressed only when there is likely to be a dispute about the economics of a proposed rate or about the capability of a well to produce at a specified rate.

1.2 Application for a Common Purchaser Order

1.2.1 Background

The *Oil and Gas Conservation Act* (the *OGCA*) affords each owner the opportunity of obtaining its share of the production of oil or gas from any pool. Accordingly, the ERCB may issue a declaration of common purchasers of oil and gas under Sections 50(1) and 51(1) of the *OGCA*. Historically the ERCB has not received applications filed under Section 50(1) respecting common purchasers of oil, as the prorationing of oil has been handled under other legislation. However the ERCB has considered many applications under Section 51(1) respecting common purchasers of gas and, accordingly, existing practices primarily deal with the common purchasers of gas.

1.2.2 When to Make This Application

A situation that would warrant the filing of a common purchaser application with the ERCB would be when the gas reserves associated with a well are being drained by other wells producing in the same pool because the owner of the well cannot obtain a reasonable market for its gas or negotiate a share of the existing markets of other owners with producing wells in the same pool. The well owner has recourse to apply for the declaration of a common purchaser in order to recover its share of gas from the pool.

1.2.3 Terms of Application

An order under Sections 50(1) and 51(1) of the *OGCA* obliges each common purchaser, among other things, to purchase production offered for sale to it without discrimination in favour of one producer or another in the same pool. Thus, a common purchaser order would allow an owner that has been unable to obtain its own market to share in the markets obtained by other owners in the pool.

Under Section 56 of the *OGCA,* an applicant filing a common purchaser application has the option of requesting that the common purchaser order be effective retroactively to the date of the application. The ERCB considers such a request in light of the particular situation and has the discretion to grant the request, deny it, or provide some measure of retroactivity other than what was requested.

In order to give effect to a common purchaser order, an applicant filing a request for the declaration of a common purchaser of gas under Section 51(1) of the *OGCA* also has the option to request under Section 51(4)(a) or (b) that the ERCB direct

- the point at which the common purchaser shall take delivery of gas offered for sale, and
- the proportion of gas that the common purchaser shall purchase from each producer or owner offering gas for sale.

If there is a dispute as to the price to be paid by the common purchaser for the gas, either the common purchaser or an owner may also apply to the ERCB to set the price under Section 55(2). An applicant may choose to file an application for the ERCB to set the price of the gas at the same time as it files an application for declaration of a common purchaser. However, in most cases where the ERCB is prepared to grant a common purchaser order, the application for setting the price of the gas is likely to be deferred to allow for additional negotiations.

Usually it would not be necessary for an applicant making a request under Section 51(1) for the declaration of a common purchaser to also make requests under each of Sections 51(4)(a), 51(4)(b), 55(2), and 56, although each option is available if there is a dispute on each issue. For example, an application for the declaration of a common purchaser under Section 51(1) typically also includes requests under Section 51(4)(b) for allocation of production among wells in a pool and under Section 56 respecting the effective date of an order. Requests made under Sections 51 and 56 should be included in the same application. A request under Section 55(2) for the ERCB to set prices may be filed together with the initial request for the declaration of the common purchaser or after the common purchaser order has been issued and the parties have attempted but failed to reach an agreement on the price to be paid for the gas.

1.2.4 How the ERCB Processes the Application

In evaluating an application for a common purchaser order, the ERCB considers

- whether drainage has occurred subsequent to the completion of a well on the applicant's property and, if so, to what extent,
- whether opportunities have existed for the marketing of production from the applicant's property and, if so, when and the nature of them,
- future prospects for marketing the production, and
- if application is being made under Sections 51(4)(a), 51(4)(b), and/or 55(2) for the designation of a delivery point, the proportion of production to be purchased and/or the setting of the price to paid, if the applicant could not make reasonable arrangements on these matters.

Each application for a common purchaser order proceeds to a public hearing.

1.2.5 Requirements for an Application for a Common Purchaser Order (file 12 copies)

Requirements	Comments
1) A statement of what you are requesting, including a) the purchasers proposed as the common purchasers, b) the pool to which the common purchaser declaration would apply, and c) the proposed effective date of the order.	For example, Company X applies, pursuant to Section 51(1) of the *OGCA*, for an order declaring Company Z as a common purchaser of gas produced from the Woodward Viking A Pool. Company X also requests, pursuant to Section 56 of the *OGCA*, that the order be effective as of the date of the application and that, pursuant to Section 51(4)(b), the ERCB direct the proportion of gas that the common purchaser shall purchase from each producer or owner offering gas for sale.
2) A statement of whether you are requesting, pursuant to Section 51(4) or 55(2) of the *OGCA*, that the ERCB, to give effect to the common purchaser declaration, direct	

Requirements	Comments
a) the point at which the common purchaser shall take delivery of gas offered for sale, and/or	
b) the proportion of gas that the common the common purchaser shall purchase from each producer or owner offering gas for sale, and/or	
c) the price that the common purchaser shall pay for the gas.	
3) A discussion of the reasons why you are requesting the subject order, including a description of the circumstances that in your opinion have led or will lead to an inequitable situation.	
4) Evidence that your well is completed in the pool to which the common purchaser is to apply, including	
a) a net pay isopach map of the pool, including both oil and gas if there is an associated pool,	The net pay map should show the entire pool and illustrate wells outside the pool that control the edges of the pool.
b) where pool delineation or fluid interfaces are based on structural interpretation, a structure contour map of the pool and offsetting area,	
c) an interpreted and annotated log cross-section or representative well log(s) showing	If there is a dispute among the parties involved regarding the delineation of the pool(s) in question, you should include an annotated cross-section in the application; if there is no dispute respecting this issue, an annotated representative well log is sufficient.
i) stratigraphic interpretation of the zone(s) of interest,	
ii) interpretation of the fluid interfaces present,	
iii) completions and treatments to the wellbore(s), with dates,	
iv) cumulative production,	

Requirements	Comments
v) finished drilling date and kelly bushing (KB) elevation, and	
vi) the scale of the log readings, and	
d) a tabulation of the interpreted net pay, porosity, and water saturation for each well in the pool, along with the cutoffs, methodology, formulas, and constants used.	These data allow the ERCB to assess your mapping and reserves calculations requested in the following item. In addition, these data may be used to allocate production (see item 13).
5) Data showing that the well is completed and capable of producing at an economic rate from the pool to which the common purchaser order is to apply.	
6) An evaluation of the oil and gas reserves for the pool and for your lands, including	The reserves estimates confirm that there are reserves available for production.
a) an estimate of the initial oil volume and gas volume in place,	
b) an estimate of the oil and gas recovery factors,	
c) a description of the methods used in determining (a) and (b) above (i.e., material balance, volumetric analysis, model study, a comparison of analog pools), and	
d) the supporting data used in determining (a) and (b) above and the sources of the data (i.e., pressure/volume/temperature [PVT] properties and source, pressure data and source).	You should provide all data used in obtaining the reserves estimates so that your analysis can be duplicated.
7) A discussion of drainage, including	Drainage should be confirmed by summarizing at least two pressure tests obtained from the well.
a) evidence showing that the reserves underlying your lands have been drained subsequent to the completion of your well in the pool,	
b) an estimate of the total amount of drainage that has occurred from your lands since your well was completed in the pool, together with details of how the drainage was calculated, and	

Requirements	Comments
c) estimates of the present and the expected future rate of drainage of your reserves in the absence of the common purchaser order, together with the details of how the estimates were obtained.	
8) A discussion of a) the opportunities that have existed for the marketing of gas or oil produced from your property, including documentation showing your attempts to obtain a market for your gas or oil, and b) the future prospects for marketing the gas or oil.	You should have made substantial efforts to obtain your own markets and to negotiate a voluntary sharing of the existing markets of other owners in the pool. You should apply to the ERCB only as a last resort. You should also continue your efforts to resolve the matter on a voluntary basis after filing the application with the ERCB.
9) A map showing the areas in the pool from which each purchaser purchases gas or oil and the location of your property.	
10) A statement that the proposed common purchaser purchases, produces, or otherwise acquires gas or oil, as the case may be, from the pool containing your property.	
11) If appropriate, a statement specifying the reasons why all the purchasers in the pool are not being proposed as common purchasers.	
12) If you are requesting, pursuant to Section 51(4)(a) of the *OGCA*, that the ERCB, to give effect to the common purchaser declaration, direct the point at which the common purchaser shall take delivery of gas offered for sale to it, a) a discussion and documentation indicating what negotiations were carried out in regard to a delivery point and where the impasse lies,	

Requirements	Comments
b) a statement of the proposed delivery point, together with a discussion of the reasons why you propose the location,	For each case, the economic analysis should include a detailed itemization of all costs (excluding sunk costs), forecasts of production and revenue streams, and tabulations of before-tax rate of return, payback, and present value analyses.
c) analyses of the economics of the proposed delivery point and alternate delivery points, and	
d) a discussion of the development and probable future development in the area.	
13) If you are requesting, pursuant to Section 51(4)(b) of the *OGCA*, that the ERCB, to give effect to the common purchaser declaration, direct the proportion of the common purchaser's acquisitions of gas from the pool that it shall purchase from each producer or owner offering gas for sale,	The ERCB's usual practice is to allocate production among wells in a pool on a percentage basis, rather than setting any specific rate or volume. The proportion of production allocated to each well is commonly based on the following formula: *Percentage of pool production for specific well = 100 x (wellbore net pay x porosity x gas saturation x area of spacing unit or validated area for specific well)/(sum of wellbore net pay x porosity x gas saturation x area of spacing units or validated areas for all wells).*
a) a discussion and documentation indicating what negotiations were carried out in regard to distributing production among wells in the pool and where the impasse lies, and	
b) a discussion of your proposal as to how the ERCB should distribute production from the pool, including a tabulation of the percentage of total production that each well or group of wells should be allowed to produce, together with details of how the proposed scheme was obtained.	*Directive 032* and *Decision 91-8* offer discussions of the ERCB's commonly used allocation formula and the validated area concept. The ERCB has not commonly used mapping as a means to determine hydrocarbon pore volume in a spacing unit because in many cases such mapping is interpretive. The ERCB has not normally factored the deliverability of a well into an allocation formula to avoid disputes on what constitutes appropriate testing of wells. You may propose an allocation formula other than the commonly used one; however, you should include detailed justification as to why the ERCB should deviate from its usual practice in determining an allocation formula. In some cases it may be useful to set minimum rates, with a percentage allocation above the minimum rate. If a well falls below the minimum rate, other wells are restricted only to their minimum rates and not below.

Requirements	Comments
14) If you are requesting, pursuant to Section 56 of the *OGCA*, that the proposed order be effective prior to the date the order is issued but not prior to the date the application for the order was made to the ERCB, a discussion as to why the order should be effective on the requested date, including a) the steps that you have taken to market your production, and b) an indication of whether or not your well is tied into a gathering system and, if not, why the order should be made on a retroactive basis.	
15) If you are requesting, pursuant to Section 55(2) of the *OGCA*, for the ERCB to set the price that the common purchaser shall pay for the gas to be taken under a common purchaser order, a) a discussion and documentation indicating what negotiations were carried out respecting the price to be paid and where the impasse lies, and b) a statement of the price you propose be paid for the gas, together with a detailed discussion of how this price was obtained and why you believe the price proposed is fair in comparison to the price offered.	If you are not asking the ERCB to set the price of the gas to be taken by the common purchaser, you do not need to include the information noted in item 15. Your response to item 15(a) may be combined with your response to item 8. Normally, the ERCB would consider setting the price to be paid for the gas to be sold under a common purchaser order only if there were a specific dispute on the price issue. Therefore, if you are requesting the ERCB to set the price, you must show that this is a specific area of dispute and that you have made substantial efforts to negotiate a resolution to the matter prior to making this request.

1.3 Application for a Common Carrier Order

1.3.1 Background

The *Oil and Gas Conservation Act* (*OGCA*) affords each owner the opportunity of obtaining its share of the production of oil or gas from any pool and provides for economic, orderly, and efficient development in the public interest. Accordingly, the ERCB may issue a declaration of a common carrier of oil, gas, or synthetic crude oil under Section 48 of the *OGCA*.

The common carrier provisions of the *OGCA* cannot be used to gain access to an oil battery, as indicated in the ERCB letter of October 26, 2005, respecting Application No. 1398650.

1.3.2 When to Make This Application

A typical situation that would warrant the filing of a common carrier application with the ERCB would be when an owner of a capable well has a market for its gas and has made arrangements to have the gas processed at a nearby plant. Its analysis shows the existing gathering system to be the only economically feasible way, the most practical way to transport the substance in question, or clearly superior environmentally for transporting its gas to the processing plant. However, the owner has been unsuccessful in negotiating an agreement on reasonable terms to use the existing pipeline. The well owner has recourse to apply for the declaration of a common carrier in order to obtain its share of gas from the pool.

1.3.3 Terms of Application

An order under Section 48 of the *OGCA* obliges each common carrier, among other things, to transport production without discrimination as between any of the owners for whom transportation is provided. Thus, a common carrier order would allow an owner to share in the existing capacity of the pipeline.

Under Section 56 of the *OGCA*, an applicant filing a common carrier application has the option of requesting that the common carrier order be effective retroactively to the date of the application. The ERCB considers such a request in light of the particular situation and has the discretion to grant the request, deny it, or provide some measure of retroactivity other than what was requested.

In order to give effect to a common carrier order, an applicant filing a request for the declaration of a common carrier under Section 48(1) of the *OGCA* also has the option to request that the ERCB direct

- the point at which the common carrier shall take delivery of the production (Section 48(4)(a)), and
- the proportion of production to be taken by the common carrier from each producer or owner offering production to be gathered, transported, handled, or delivered by means of a pipeline (Section 48(4)(b)).

If there is a dispute as to the tariff to be paid to the common carrier, either the common carrier or an owner may also apply for the ERCB to set the price under Sections 55(1) or 55(3) of the *OGCA*. An applicant may choose to file an application for the ERCB to set tariffs at the same time as it files an application under Section 48. However, in most cases where the ERCB is prepared to grant a common carrier order, the application for the setting of tariffs may be deferred to allow for additional negotiations.

Usually it would not be necessary for an applicant making a request under Section 48(1) of the *OGCA* for the declaration of a common carrier to also make requests under each of Sections 48(4)(a), 48(4)(b), 55(1) or (3), and 56, although each option is available if there is a dispute on each issue. For example, an application for the declaration of a common carrier under Section 48(1) typically also includes requests under Section 48(4)(b) for allocation of production among wells in a pool and under Section 56 respecting the effective date of an order. Requests under Sections 48 and 56 should be included in the same application. A request under Section 55(1) or (3) for the ERCB to set a transportation fee may be filed together with the initial request for the declaration of the common carrier or after the common carrier order has been issued and the parties have attempted but failed to reach an agreement on the fee to be paid.

1.3.4 How the ERCB Processes the Application

In evaluating an application for a common carrier order, the ERCB considers whether the applicant has demonstrated that

- producible reserves are available for transportation through an existing pipeline,
- there is a reasonable expectation of a market for the substance that is proposed to be transported by the common carrier operation,
- the applicant could not make reasonable arrangements to use the existing pipeline,
- the proposed common carrier operation is the only economically feasible way, the most practical way to transport the substance in question, or clearly superior environmentally, and
- where application is being made under Sections 48(4)(a), 48(4)(b), or 55(1) or (3) of the *OGCA* for the designation of a delivery point, the proportion of production to be delivered to the pipeline, and/or the setting of the transportation fee to be paid, the applicant could not make reasonable arrangements on these matters.

Each common carrier application proceeds to a public hearing.

1.3.5 Requirements for an Application for a Common Carrier Order (file 12 copies)

Requirements	Comments
1) A statement of what is being requested, including a) a reference that you are making the application under Section 48 of the *OGCA*,	For example, Company X applies under Section 48 of the *OGCA* for an order declaring Company Z to be a common carrier of gas produced from the Woodward Viking A Pool through a pipeline extending from LSD x to LSD y and including a field compressor located in LSD z. Company X

Requirements	Comments
b) the name of the company to be designated as the common carrier, c) reference to the pool or pools to which the proposed common carrier declaration would apply, or if it is proposed that the order not apply to any specific pool, a discussion as to why the order should not apply to a specific pool or pools, d) the location of the pipeline(s) to which the proposed common carrier order would apply, including the proposed tie-in and terminating points, and e) the proposed effective date of the order.	also requests, pursuant to Section 56 of the *OGCA*, that the order be effective as of the date of the application and that, pursuant to Section 48(4)(b) of the *OGCA*, the ERCB direct the proportion of production to be taken by the common carrier from each producer or owner.
2) A statement of whether you are requesting, pursuant to Section 48(4) or 55(1) or (3) of the *OGCA,* that the ERCB, to give effect to the common carrier declaration, direct a) the point at which the common carrier shall take delivery of production, and/or b) the proportion of production to be taken by the common carrier from each producer or owner, and c) the transportation fee that shall be paid to the common carrier.	See comments for items 13, 14, and 16.
3) A discussion giving the reasons why you are requesting the subject order, including a description of the circumstances that in your opinion have led or will lead to an inequitable situation.	
4) Documentation showing that reasonable arrangements for the use of the pipeline could not be agreed upon, including a) identification of all parties involved and the nature of their issues and concerns, and	You should have made substantial efforts to negotiate a resolution to the matter prior to filing an application with the ERCB. The application should be a last resort. You should also continue your efforts to resolve the matter on a voluntary basis (including consideration of a third-party mediator) after filing the application with the ERCB.

Requirements	Comments
b) an outline of the attempts to resolve the issues, including type of discussions held, timing, and frequency.	Your discussion must include why the negotiations did not lead to a settlement and what dispute resolution efforts were conducted. Matters of confidentiality and disclosure should be addressed and determined by the parties prior to submission of the application. The documentation should illustrate your case that you have been unable to obtain reasonable arrangements. Matters of dispute may include access on terms that would allow you to obtain your share of production from the pool at reasonable fees.
5) A statement specifying the operator and ownership of the pipeline to be subject to the proposed order.	
6) An indication of the available capacity of the pipeline to be subject to the proposed common carrier order.	
7) A map showing the location of the subject pool, pipeline(s), any alternative facilities, and your production facilities.	
8) Your geological interpretation of the pool involved, including	
a) a net pay isopach map of the pool, including both oil and gas if there is an associated pool,	The net pay map should show the entire pool and illustrate wells outside the pool that define the edges of the pool.
b) where pool delineation or fluid interfaces are based on structural interpretation, a structure contour map of the pool and offsetting area,	
c) an interpreted and annotated log cross-section or representative well log(s) showing i) stratigraphic interpretation of the zone(s) of interest,	If there is a dispute among the parties involved regarding the delineation of the pool(s) in question, you should include an annotated cross-section in the application; where there is no dispute respecting this issue, an annotated representative well log is sufficient.

Requirements	Comments
ii) interpretation of the fluid interfaces present,	
iii) completions and treatments to the wellbore(s), with dates,	
iv) cumulative production,	
v) finished drilling date and kelly bushing (KB) elevation, and	
vi) the scale of the log readings, and	
d) a tabulation of the interpreted net pay, porosity, and water saturation for each well in the pool, along with the cutoffs, methodology, formulas, and constants used.	These data assist the ERCB to assess your mapping and reserves calculations requested in the following item. In addition, these data may be used to allocate production (see item 14).
9) An evaluation of the oil and gas reserves for the pool and for your lands, including	The reserves estimates confirm that there are reserves available for production.
a) an estimate of the initial oil volume and gas volume in place,	
b) an estimate of the oil and gas recovery factors,	
c) a description of the methods used in determining (a) and (b) above (e.g., material balance, volumetric analysis, model study, a comparison of analog pools), and	
d) the supporting data used in determining (a) and (b) above and the sources of the data (i.e., pressure/volume/temperature [PVT] properties and source, pressure data and source).	You should provide all data used in obtaining the reserves estimates so that your analysis can be duplicated.
10) A discussion of drainage, including	Drainage is not a prerequisite for the issuance of a common carrier order but could be one factor in determining the need for an order. In addition, the ERCB would consider the extent to which drainage has occurred in evaluating what the effective date of the order should be.
a) evidence showing that the reserves underlying your lands have been drained subsequent to the completion of your well in the pool, and	
b) an estimate of the total amount of	In cases where a well has remained shut in,

Requirements	Comments
inequitable drainage that has occurred from your lands since your well was completed in the pool, together with details of how the drainage was calculated.	you may confirm drainage by summarizing a minimum of two pressure tests taken on the well. If you are arguing that your currently producing well is not producing at sufficient rates to recover an equitable share of production, you may make a comparison between the actual produced volume from the well and the volume the well should have produced to obtain an equitable share of production. You should present a detailed calculation showing how you determined your equitable share of production.
11) A discussion of the practicability, economics, and any environmental concerns of a) the proposed common carrier operation, b) the alternative of building new facilities, c) the alternative of using other facilities (such as taking the gas to another existing plant), and d) any other alternatives available.	For each case, the economic analysis should include a detailed itemization of all costs used (excluding sunk costs), forecasts of production and revenue streams, and tabulations of before-tax rate of return, payback, and present value analyses.
12) A discussion of the availability or the reasonable expectation of a market for the oil, gas, or synthetic crude oil that would be transported in the common carrier operation.	
13) If you are requesting, pursuant to Section 48(4)(a) of the *OGCA*, that the ERCB, to give effect to the common carrier declaration, direct the point at which the common carrier shall take delivery of any production to be gathered, transported, handled, or delivered by means of the subject pipeline, a) a discussion and documentation indicating what negotiations were carried out in regard to a delivery point and where the impasse lies, b) a statement of the proposed delivery point, together with a discussion of the	

Requirements	Comments
reasons why you propose the location, c) analyses of the economics of the proposed delivery point and alternative delivery points, and d) a discussion of the development and probable future development in the area.	For each case, the economic analysis should include a detailed itemization of all costs (excluding sunk costs), forecasts of production and revenue streams, and tabulations of before-tax rate of return, payback, and present value analyses.
14) If you are requesting, pursuant to Section 48(4)(b) of the *OGCA*, that the ERCB, to give effect to the common carrier declaration, direct the proportion of production to be taken by the common carrier from each producer or owner offering production to be gathered, transported, handled, or delivered by means of the subject pipeline, a) a discussion and documentation indicating what negotiations were carried out in regard to distributing production among wells in the pool and where the impasse lies, and b) a discussion of your proposal as to how the ERCB should distribute production from the pool that includes a tabulation of the proportion or percentage of total production that each well or group of wells should be allowed to produce, together with the details of how the proposed production scheme was obtained.	The ERCB's usual practice is to allocate production among wells in a pool on a percentage basis, rather than setting any specific rate or volume. The proportion of production allocated to each well is commonly based on the following formula: *Percentage of pool production for specific well = 100 x (wellbore net pay x porosity x gas saturation x area of spacing unit or validated area for specific well)/(sum of wellbore net pay x porosity x gas saturation x area of spacing units or validated areas for all wells).* *Directive 032 and Decision 91-8* offer discussions on the ERCB's commonly used allocation formula and the validated area concept. The ERCB has not generally used mapping as a means to determine hydrocarbon pore volume in a spacing unit because in many cases such mapping is highly interpretive. The ERCB has not normally factored the deliverability of a well into an allocation formula to avoid disputes on what constitutes appropriate testing of wells. You may propose an allocation formula other than the commonly used one; however, you should offer detailed justification as to why the ERCB should deviate from its consistent practice in determining an allocation formula. In some cases it may be useful to set minimum rates, with a percentage allocation above the minimum rate. If a well falls below the minimum rate, other wells are restricted only to their minimum rates and not below.
15) If you are requesting, pursuant to Section 56 of the *OGCA,* that the proposed order be effective prior to the date the order is issued	

Requirements	Comments
but not prior to the date the application for the order was made to the ERCB, a discussion as to why the order should be effective on the requested date, including a) the steps that you have taken to market your production, and b) an indication of whether your well is tied into a gathering system and, if not, why the order should be made on a retroactive basis.	
16) If you are requesting, pursuant to Section 55(1) or (3) of the *OGCA*, that the ERCB set the fee to be paid to the common carrier for the transportation of the gas or oil, a) a discussion and documentation indicating what negotiations were carried out respecting the fee to be paid and where the impasse lies, b) a statement of the fee you propose be paid for the transportation of the gas or oil under the common carrier order, together with a discussion of why you believe the fee proposed is fair in comparison to the fee offered, c) if you have calculated the fee you propose be paid using the *JP-05* formulas, i) a tabulation of the values used in the calculations, and ii) a discussion of the basis and/or source for each value used in the calculation, and d) if you have calculated the fee you propose be paid using a methodology other than the *JP-05* formulas (see Comments column), a detailed discussion of how the fee was obtained and why the ERCB should used the methodology proposed rather than the *JP-05* formula.	If you are not asking the ERCB to set the tariff to be charged by the common carrier for the transportation of the gas under the common carrier order, you do not need to include the information noted in item 16. Your response to item 16(a) may be combined with your response to item 4. Normally, the ERCB would consider setting the fee to be paid under a common carrier order only if there were a specific dispute on the fee issue. Therefore, if you are requesting the ERCB to set the fee, you must show that this is a specific area of dispute and that you have made substantial efforts to negotiate a resolution to the matter prior to making this request. *Decision 2006-021* confirms the ERCB's support for the setting of tariffs and fees using the formula and principles set out in *JP-05: A Recommended Practice for the Negotiation of Processing Fees* (*JP-05*). You may propose an alternative way of calculating a fair fee other than the *JP-05* formula; however, you should offer detailed justification as to why the ERCB should not use the *JP-05* formula for the case in question.

1.4 Application for a Common Processor Order

1.4.1 Background

The *Oil and Gas Conservation Act* (*OGCA*) affords each owner the opportunity of obtaining its share of the production of oil or gas from any pool and provides for economic, orderly, and efficient development in the public interest. Accordingly, the ERCB may issue a declaration of a common processor of gas under Section 53 of the *OGCA*.

1.4.2 When to Make This Application

A typical situation that would warrant the filing of a common processor application with the ERCB would be when an owner of a capable well has a market for its gas requiring processing to meet contract specifications. The owner believes that using the existing plant is the only economically feasible or most practical way to process the gas in question or is clearly superior environmentally, but the owner has been unsuccessful in negotiations to gain access to the plant on reasonable terms. The owner has recourse to apply for the declaration of a common processor in order to gain access to the plant and allow it to obtain its share of gas from the pool.

1.4.3 Terms of Application

An order under this section obliges each common processor, among other things, to process gas that may be made available for processing in the plant without discrimination in favour of one producer or owner as against another in the pool.

Under Section 56 of the *OGCA*, an applicant filing a common processor application has the option of requesting that the common processor order be effective retroactively to the date of the application. The ERCB considers such a request in light of the particular situation and has the discretion to grant the request, deny it, or provide some measure of retroactivity other than that requested.

In order to give effect to a common processor order, an applicant filing a request for the declaration of a common processor also has the option of requesting that the ERCB direct

- the proportion of production to be processed by the common processor from each producer or owner in the pool (Section 53(5)(a)), and/or
- the total amount of gas to be processed by the common processor from the pool subject to the common processor declaration (Section 53 (5)(b)).

If there is a dispute as to the tariff to be paid to the common processor, either the common processor or an owner may also apply under Section 55(2) of the *OGCA* for the ERCB to set the price.

An applicant may choose to file an application for the ERCB to set fees at the same time as it files an application under Section 53. However, in most cases where the ERCB is prepared to grant a common processor order, the application for the setting of tariffs may be deferred to allow for additional negotiations.

Usually it would not be necessary for an applicant making a request under Section 53(1) for the declaration of a common processor to also make requests under each of Sections 53(5)(a), 48(5)(b), 55(2), and 56, although each option is available if there is a dispute on each issue. For example, an application for the declaration of a common processor under Section 53(1) typically also includes requests under Section 53(5)(a) for allocation of production among wells in a pool and under Section 56 respecting the effective date of an order. Requests under Sections 53 and 56 should be included in the same application. A request under Section 55(2) for the ERCB to set a processing fee may be filed together with the initial request for the declaration of the common processor or after the common processor order has been issued and the parties have attempted but failed to reach an agreement on the fee to be paid.

1.4.4 How the ERCB Processes the Application

In evaluating an application for a common processor order, the ERCB considers whether the applicant has demonstrated that

- producible reserves are available for processing and processing facilities are needed,
- reasonable arrangements for use of processing capacity in the subject processing plant could not be agreed upon by the parties,
- the proposed common processor operation is either the only economically feasible or most practical way to process the gas in question or is clearly superior environmentally, and
- when an application is being made under Sections 42(5)(a), 42(5)(b), and/or 55(2) of the *OGCA* for the allocation of production, a direction of the total volume of gas from the pool to be processed at the plant, and/or the setting of a processing fee, the applicant could not make reasonable arrangements on these matters.

Each application for a common processor order proceeds to a public hearing.

1.4.5 Requirements for an Application for a Common Processor Order (file 12 copies)

Requirements	Comments
1) A statement of what is being requested, including a) a reference that you are making the application under Section 53 of the *OGCA*, b) the name of the company to be designated as the common processor, c) a reference to the pool or pools to which the proposed common processor declaration would apply, d) the name and the location of the processing plant to which the proposed common processor order would apply, and	For example, Company X applies under Section 53 of the *OGCA* for an order declaring Company Z to be a common processor of gas produced from the Woodward Viking A Pool through the Grande Coulee Gas Plant located at LSD. Company X also requests, pursuant to Section 45 of the *OGCA*, that the order be effective as of the date of the application and that, pursuant to Section 42(5)(a) of the *OGCA*, the ERCB direct the proportion of production to be taken by the common processor from each producer or owner in the Woodward Viking A Pool.

Requirements	Comments
e) the proposed effective date of the order.	
2) A statement of whether you are requesting, pursuant to Section 53(5) or 55(2) of the *OGCA*, that the ERCB, in order to give effect to the common processor declaration, direct a) the proportion of production to be processed by the common processor from each producer or owner in the pool or pools, b) the total amount of gas to be processed by the common processor from the pool or pools subject to the common processor declaration, and/or a) the processing fee that shall be paid to the common processor.	See comments for items 14, 15, and 17.
3) A discussion giving the reasons why you are requesting the order, including a description of the circumstances that in your opinion have led or will lead to an inequitable situation.	
4) Documentation showing that reasonable arrangements for the use of processing capacity in the plant could not be agreed upon, including a) identification of all parties involved and the nature of their issues and concerns, and b) an outline of the attempts to resolve the issues, including type of discussions held, timing, and frequency.	You should have made substantial efforts to negotiate a resolution to the matter prior to filing an application with the ERCB. The application should be a last resort. You should also continue your efforts to resolve the matter on a voluntary basis (including consideration of a third-party mediator) after you have filed the application with the ERCB. Your discussion must include why the negotiations did not lead to a settlement and what dispute resolution efforts were conducted. Matters of confidentiality and disclosure should be addressed and determined by the parties prior to submission of the application. The documentation should illustrate your case that you have been unable to obtain reasonable arrangements. Matters of dispute may include access on terms that would allow you to obtain your show or production from the pool at reasonable tariffs.

Requirements	Comments
5) A map showing the location of the subject pool, processing plant, any alternative facilities, and your production facilities.	
6) A statement specifying the operator and ownership of the processing plant.	
7) A discussion of	
a) the total processing capacity of the plant,	
b) the volumes of gas from the pool or pools to be subject to the proposed common processor declaration and from other pools currently processed at the subject plant, and	
c) the processing capacity available to you in the plant.	
8) An analysis of the composition of the gas to be processed under the common processor declaration, together with a discussion as to the capability of the plant to process the subject gas.	
9) Your geological interpretation of the pool involved, including	
a) a net pay isopach map of the pool, including both oil and gas if there is an associated pool,	The net pay map should show the entire pool and illustrate wells outside the pool that control the edges of the pool.
b) where pool delineation or fluid interfaces are based on structural interpretation, a structure contour map of the pool and offsetting area,	
c) an interpreted and annotated log cross-section or representative well log(s) showing i) stratigraphic interpretation of the zone(s) of interest, ii) interpretation of the fluid interfaces present,	If there is a dispute among the parties involved regarding the delineation of the pool(s) in question, you should include an annotated cross-section in the application; if there is no dispute respecting this issue, an annotated representative well log is sufficient.

Requirements	Comments
iii) completions and treatments to the wellbore(s), with dates,	
iv) cumulative production,	
v) finished drilling date and kelly bushing (KB) elevation, and	
vi) the scale of the log readings, and	
d) a tabulation of the interpreted net pay, porosity, and water saturation for each well in the pool, along with the cutoffs, methodology, formulas, and constants used.	These data assist the ERCB to assess your mapping and reserves calculations requested in the following item. In addition, the data may be used to allocate production (see item 14).
10) An evaluation of the oil and gas reserves for the pool and for your lands, including	The reserve estimates confirm that there are reserves available for production.
a) an estimate of the initial oil volume and gas volume in place,	
b) an estimate of the oil and gas recovery factors,	
c) a description of the methods used in determining (a) and (b) above (e.g., material balance, volumetric analysis, model study, a comparison of analog pools), and	
d) the supporting data used in determining (a) and (b) above and the sources of the data (e.g., pressure/volume/temperature [PVT] properties and source, pressure data and source).	You should provide all data used in obtaining the reserves estimates so that your analysis can be duplicated.
11) A discussion of drainage, including	Drainage is not a prerequisite for the issuance of a common processor order but could be one factor in determining the need for an order. In addition, the ERCB considers the extent to which drainage has occurred in evaluating what the effective date of the order should be.
a) evidence showing that the reserves underlying your lands have been drained subsequent to the completion of your well in the pool, and	
b) an estimate of the total amount of inequitable drainage that has occurred from your lands since your well was completed in the pool, together with	In cases where a well has remained shut in, you can confirm drainage by summarizing a minimum of two pressure tests taken on the well. If you are arguing that your currently

Requirements	Comments
details of how the drainage was calculated.	producing well is not producing at sufficient rates to recover an equitable share of production, you may make a comparison between the actual produced volume from the well and the volume the well should have produced to obtain an equitable share of production. You should present a detailed calculation showing how you determined your equitable share of production.
12) A discussion of the practicability, economics, and any environmental concerns of a) the proposed common processor operation, b) the alternative of building new facilities, c) the alternative of using other facilities (such as taking the gas to another existing plant), and d) any other alternatives available.	For each case, the economic analysis should include a detailed itemization of all costs (excluding sunk costs), forecasts of production and revenue streams, and tabulations of before-tax rate of return, payback, and present value analyses.
13) A discussion of the availability or the reasonable expectation of a market for your gas that would be processed at the plant.	
14) If you are requesting, pursuant to Section 53(5)(a) of the *OGCA,* that the ERCB, in order to give effect to the common processor declaration, direct the proportion of production to be processed by the common processor from each producer or owner in the pool or pools, a) a discussion and documentation indicating what negotiations were carried out in regard to distributing production among wells in the pool and where the impasse lies, and b) a discussion of your proposal as to how the ERCB should distribute production from the pool, including a tabulation of the proportion or percentage of total production that each well or group of	The ERCB's usual practice is to allocate production among wells in a pool on a percentage basis, rather than setting any specific rate or volume. The proportion of production allocated to each well is commonly based on the following formula: *Percentage of pool production for specific well = 100 x (wellbore net pay x porosity x gas saturation x area of spacing unit or validated area for specific well)/(sum of wellbore net pay x porosity x gas saturation x area of spacing units or validated areas for all wells).* *Directive 032* and *Decision 91-8* offer discussions of the ERCB's commonly used allocation formula and the validated area concept. The ERCB has not generally used mapping as a means to determine

Requirements	Comments
wells should be allowed to produce, together with the details of how the proposed production scheme was obtained.	hydrocarbon pore volume in a spacing unit because in many cases such mapping is highly interpretive. The ERCB has not normally factored the deliverability of a well into an allocation formula to avoid disputes on what constitutes appropriate testing of wells. You may propose an allocation formula other than the commonly used one; however, you should offer detailed justification as to why the ERCB should deviate from its consistent practice in determining an allocation formula. In some cases it may be useful to set minimum rates, with a percentage allocation above the minimum rate. If a well falls below the minimum rate, other wells are restricted only to their minimum rates and not below.
15) If you are requesting, pursuant to Section 53(5)(b) of the *OGCA,* that the ERCB, in order to give effect to the common processor declaration, direct the total amount of gas to be processed by the common processor from the pool or pools subject to the common processor declaration, a) a statement of why you believe such a total volume should be set, b) a discussion and documentation indicating what negotiations were carried out in regard to the total amount of gas to be processed by the common processor from the pool or pools subject to the common processor declaration and where the impasse lies, and c) a statement of the total amount of gas you propose be processed by the common processor from the pool or pools subject to the common processor, together with a discussion of how the volume was determined.	
16) If you are requesting, pursuant to Section 56 of the *OGCA*, that the proposed order be effective prior to the date the order is issued but not prior to the date the application for the	

Requirements	Comments
order was made to the ERCB, a discussion as to why the order should be effective on the requested date, including a) the steps that you have taken to market your production, and b) an indication of whether your well is tied into a gathering system and, if not, why the order should be made on a retroactive basis.	
17) If you are requesting, pursuant to Section 55(2) of the *OGCA*, for the ERCB to set the processing fee to be paid to the common processor, a) a discussion and documentation indicating what negotiations were carried out respecting the fee to be paid and where the impasse lies, b) a statement of the processing fee you propose be paid, together with a discussion of why you believe the tariff proposed is fair in comparison to the tariff offered, c) if you have calculated the processing fee you propose be paid using the *JP-05* formula (see Comments column), i) a tabulation of the values in the calculations, and ii) a discussion of the basis and/or source for each value used in the calculation, and d) if you have calculated the processing fee you propose be paid using a methodology other than the *JP-05* formula, a detailed discussion of how the fee was obtained and why the ERCB should used the methodology proposed rather than the *JP-05* formula.	If you are not asking the ERCB to set processing fees, you do not need to include the information noted in item 17. Your response to item 17(a) may be combined with your response to item 4. Normally, the ERCB would consider setting processing fees only if there were a specific dispute on the fee issue. Therefore, if you are requesting the ERCB to set the processing fee, you must show that this is a specific area of dispute and that you have made substantial efforts to negotiate a resolution to the matter prior to making this request. *Decision 2006-021* confirms the ERCB's support for the setting of fees using the formula and principles set out in *JP-05: A Recommended Practice for the Negotiation of Processing Fees* (*JP-05*). You may propose an alternative way of calculating a fair processing fee other than the *JP-05* formula; however, you should offer detailed justification as to why the ERCB should not use the *JP-05* formula for the case in question.

1.5 Application for a Compulsory Pooling Order

1.5.1 Background

Section 5.005 of the *Oil and Gas Conservation Regulations* specifies that no well shall be produced unless there is common ownership throughout the drilling spacing unit (DSU). This means that if there are separate tracts within a DSU with different ownership, all owners within the DSU must have an arrangement to share in the costs and revenues associated with drilling and producing a well from that spacing unit. This type of arrangement is generally referred to as a pooling agreement. In most cases, mineral holders negotiate voluntary pooling arrangements. However, if an owner attempts but fails to negotiate a satisfactory pooling arrangement in a reasonable period of time, or a tract owner is missing and untraceable, or there is a dispute as to the ownership of a tract, the owner wishing to drill a well may apply to the ERCB for a compulsory pooling order. This order serves the same purpose as a voluntary pooling arrangement by ensuring that each owner in the DSU shares appropriately in the costs and revenues associated with a well in the DSU.

The ERCB's role in pooling matters, therefore, is to offer a regulatory avenue to resolve problems relating to pooling issues, thereby allowing each owner the opportunity to obtain its share of oil and gas from any pool.

Applications for compulsory pooling are made

- under Section 80 of the *Oil and Gas Conservation Act* (*OGCA*);
- if there is a missing and untraceable owner in the spacing unit, under both Sections 80 and 85 of the *OGCA* (Section 85 provides that the revenues associated with the missing and untraceable owner be paid to the Public Trustee); and
- if there is a dispute as to the ownership of a tract or ownership is unknown, under both Sections 80 and 86 of the *OGCA* (Section 86 provides that revenues associated with the disputed tract be paid to the Provincial Treasurer to be held in trust pending an order of the Court of Queen's Bench or until a settlement has been reached by the parties).

The ERCB's current policies and practices respecting pooling arise from a combination of specific provisions of the *OGCA*, historical decisions made by the ERCB, consultations with industry, and ERCB decisions resulting from pooling applications considered at public hearings. These avenues have resulted in an ERCB pooling order with standard terms. Nonstandard terms are included in an order only if there is substantial justification to do so. General information on major ERCB policies and practices respecting pooling and the standard terms of a pooling order are noted below in the Requirements sections. More detailed information can be obtained from ERCB staff.

1.5.2 How the ERCB Processes the Application

ERCB staff initially review a pooling application for completeness. If additional information is required, a letter is issued itemizing the information required. Processing of the application is deferred pending receipt of the requested information.

Except in cases involving missing and untraceable owners or minor amendments to existing pooling orders, once an application is complete the ERCB normally issues a notice of hearing respecting the application. The notice of hearing would not usually be published in any newspapers but sent directly to parties with an interest in the petroleum and/or natural gas underlying the DSU. Interested parties would have a specified time period in which to file any objections they may have respecting the application.

If no objections are received in response to the notice of hearing, the ERCB cancels the hearing and makes a decision on the application without a hearing. When approval is granted, the ERCB proceeds with the steps required to issue a pooling order. This includes obtaining the approval of the Lieutenant Governor in Council to issue the order. If a valid objection to an application is filed, the scheduled hearing would proceed and the ERCB would consider the application and the concerns raised.

In a few cases when it is warranted, the ERCB may issue a notice of applications, rather than a notice of hearing. Again, the notice of applications is not usually published in any newspapers but is sent directly to parties with an interest in the petroleum and/or natural gas underlying the DSU. Interested parties would have a specified time period in which to file any objections they may have respecting the application. If no objections are received in response to the notice of applications, the ERCB makes a decision on the application without further notice or a hearing. When approval is granted, the ERCB proceeds with the steps required to issue a pooling order. This includes obtaining the approval of the Lieutenant Governor in Council to issue the order.

If a valid objection to an application is filed, the ERCB schedules a public hearing to consider the application and the concerns raised.

1.5.3 Requirements for an Application for a Compulsory Pooling Order (file 12 copies)

Requirements	Comments
1) A statement of what you are requesting, including a) a reference to the section(s) of the *OGCA* under which you are making the application, and	You should cite Section 80 of the *OGCA* and, if applicable, Sections 85 and 86. For example: Company X is applying for a compulsory pooling order for the production of gas under Section 80 of the *OGCA* in the DSU constituting Section 13-45-12W4M.
b) the legal description of the DSU involved.	The size of the DSU involved should be consistent with the substance to be pooled (oil or gas). Thus, oil would normally be pooled within a standard oil DSU of a quarter section, while gas would be pooled within a standard gas DSU of one section. Compulsory pooling occurs only within a single DSU. Section 80 of the *OGCA* does not allow for compulsory pooling within several DSUs.

Requirements | **Comments**

2) A statement providing the legal description of each tract within the DSU and the ownership of that tract, together with a table showing the mailing addresses for all lessors and lessees (except the Crown).

For example. for the gas DSU constituting Section 13-45-12W4M:

	Ownership		
Tract	Lessor		Lessee
SW quarter	Crown		Company A
SE quarter	Freehold –	½ undivided J. Doe	Company A
		½ undivided P. Doe	Not leased
North half	Freehold	Company B	Company A

You should provide the mailing addresses of all lessors (except the Crown) and lessees as an attachment to the application. This allows the ERCB to provide notice of the application to all potentially adversely affected parties.

3) A statement of the formation to which you propose to drill or from which you propose to produce.

The formation subject to the pooling order would be cited in the order. In previous pooling applications where there has been a dispute about which formations should be subject to a pooling order, the ERCB decided to limit the formation subject to the order to the known productive zone or to the major productive zone (*Examiner Reports 91-6* and *95-2*).

4) A statement that an agreement to operate the tracts as a unit cannot be made on reasonable terms.

5) The particulars of the efforts you have made to obtain a voluntary agreement, including

   a) identification of all parties involved and the nature of their issues and concerns,

   b) an outline of the attempts to resolve the issues, including type of discussions held, timing, and facilities, and

   c) an indication of your view of why attempts to obtain a voluntary pooling arrangement have failed in each case.

You should have made substantial efforts to negotiate a voluntary pooling arrangement. The application should be a last resort. You should also continue your efforts to resolve the matter on a voluntary basis (including considerations of a third-party mediator) after filing the application with the ERCB.

Your discussion must include why the negotiations did not lead to a settlement and what dispute resolution efforts were conducted. Matters of confidentiality and disclosure should be addressed and determined by the parties prior to submission of the application.

A description of your efforts to resolve the situation should include a summary of

Requirements	Comments
	telephone calls and meetings and copies of relevant correspondence.
6) If there is a well on the DSU that is to be produced under the proposed pooling order, a statement of the unique identifier of the well and its producing formation or formations.	The well to be subject to the pooling order would be cited in the pooling order.
7) If there is not a well on the DSU drilled to the formation(s) referred to in item 3, a statement indicating the location (LSD) of the well to be drilled.	The proposed well location would be included in the pooling order.
8) If there is not a well on the DSU drilled to the formation(s) referred to in item 3, a statement that if an order is made by the ERCB, you are prepared to drill a well to the formation(s) in question, and in the event that no production of gas or oil is obtained, you will pay all costs incurred in the drilling and abandonment of the well in accordance with Section 80(2)(f) of the *OGCA*.	
9) If there is not a well drilled on the DSU, an indication of whether you would see any difficulty in drilling the well within six months of the date of the proposed order if issued, and if so, an indication of what would be a more appropriate time limit to drill.	Section 74(2) of the *OGCA* implies that a well should be drilled within six months of the date of the order.
10) A statement of the operator to be appointed for the well of interest in the proposed pooling order.	All pooling orders normally include a clause that names the operator of the well subject to the pooling order.
11) A statement that the allocation of costs and revenues under the pooling order would be on a tract area basis, or if allocation is proposed to be on a basis other than an area basis, the proposed allocation and the details of how the allocation was determined, including	Section 80(4)(c) of the *OGCA* indicates that allocation shall be on an area basis unless it can be shown to the ERCB that this is inequitable. Thus, allocation on an area basis is the normal provision of a pooling order, and an applicant would not need to justify why it has chosen to request an area-based allocation.

Requirements	Comments
a) a net pay isopach map of the pool, including both oil and gas if there is an associated pool,	
b) if pool delineation or fluid interfaces are based on structural interpretation, a structure contour map of the pool and offsetting area,	
c) an interpreted and annotated log cross-section or representative well log(s) showing i) stratigraphic interpretation of the zone(s) of interest, ii) interpretation of the fluid interfaces present, iii) completions and treatments to the wellbore(s), with dates, iv) cumulative production, v) finished drilling date and kelly bushing (KB) elevation, and vi) the scale of the log readings, and	If there is a dispute among the parties involved regarding the delineation of the pool(s) in question, you should include an annotated cross-section in the application; if there is no dispute respecting this issue, an annotated representative well log is sufficient.
d) a tabulation of the interpreted net pay, porosity, and water saturation for each well in the pool, along with the cutoffs, methodology, formulas, and constants used.	
12) A statement indicating whether you are proposing that the requested order provide for the equalization of the actual cost of drilling the well to and completing it in the formation(s) named in the pooling order, in accordance with Section 80(4)(d) of the *OGCA*.	This is a standard provision of a typical pooling order. It applies to a situation where an applicant has itself drilled a well for the purpose of producing the zone to be subject to the pooling order or is proposing to drill such a well. If the case is not the standard one—for example, if a well was drilled and produced from a zone other than the one to be subject to the pooling order—it would normally be appropriate to modify the standard provision such that not all original drilling and completion costs would be shared.

Requirements	Comments
13) A statement as to whether you are proposing that the requested order provide for a penalty to be imposed against actual drilling and completion costs in accordance with Section 80(5) of the *OGCA* and, if so, a) what penalty should be imposed, b) the justification for the proposed penalty, and c) confirmation that in accordance with normal ERCB practice, you would agree that the proposed penalty would be applied if the tract owner did not pay its share of actual drilling and completion costs within 30 days of the pooling order being issued, the well commencing production, and the tract owner being notified in writing of its share of costs, whichever is later; or if you are proposing an alternative to the ERCB's normal practice, a justification of why the ERCB should depart from its normal practice in this case.	A penalty under Section 80(5) of the *OGCA* is a standard provision of pooling orders involving disputes between industry players. In these cases, the ERCB has normally provided for the maximum penalty allowed by Section 80(5). That is, if the maximum penalty applies and a tract owner has chosen to incur the penalty rather than pay costs "up front," the tract owner would owe the well operator its share costs plus the penalty of two times the cost. If the tract owner's share of costs were $10 000 and it chose to incur the penalty, it would pay costs of $10 000 plus two times the costs, equalling $20 000, for a total of $30 000.

Unit 2 Conservation

2.1 Application for an Enhanced Recovery Scheme

2.1.1 Introduction

2.1.1.1 Background

Enhanced recovery (ER) involves the improvement of hydrocarbon recovery through the injection of fluid(s) into a hydrocarbon reservoir to

- add to or maintain reservoir energy (pressure),
- displace hydrocarbons to production wells, or
- alter the reservoir fluids so that hydrocarbon flow and recovery are improved.

An application to implement or amend an ER scheme is required in accordance with Section 39(1)(a) of the *Oil and Gas Conservation Act*. Additional approvals from the ERCB or other government agencies may also be required to implement an ER scheme.

If changes to an existing ER scheme approval are required, an application must be made for the appropriate amendment(s).

2.1.1.2 Application Process

A) How to Make an ER Scheme Application

An ER application must be made using the Enhanced Recovery Scheme application form (see Appendix F). This form, in addition to Schedule 1 and the required attachments, must be included in the application. This information should be submitted electronically using the Electronic Application Submission (EAS) process accessed through the Digital Data Submission (DDS) screen on the ERCB's Web site www.ercb.ca. The ERCB will validate all applications to ensure that the requirements for ER schemes have been met. Incomplete applications or those containing significant errors will be closed.

This application process does not apply to crude bitumen ER schemes in the oil sands areas. An application for these schemes must be submitted in paper form (outside of EAS) and must comply with the *Oil Sands Conservation Act* (Section 10 for new schemes, or Section 13 for an amendment to an existing scheme).

B) How the ERCB Processes the Application

The ERCB reviews all ER scheme applications to ensure that hydrocarbon recovery will be optimized and that all ER scheme requirements are met. ER scheme applications meeting the base criteria detailed in Figure 2.1 will be processed in an expedited manner under a quick ER application process.

Those applications qualifying for the quick process will be dispositioned under a process that shifts the review emphasis from scheme design (application) to scheme performance (audit). Applications not meeting these base criteria will require a more detailed review addressing those areas in which the criteria are not met.

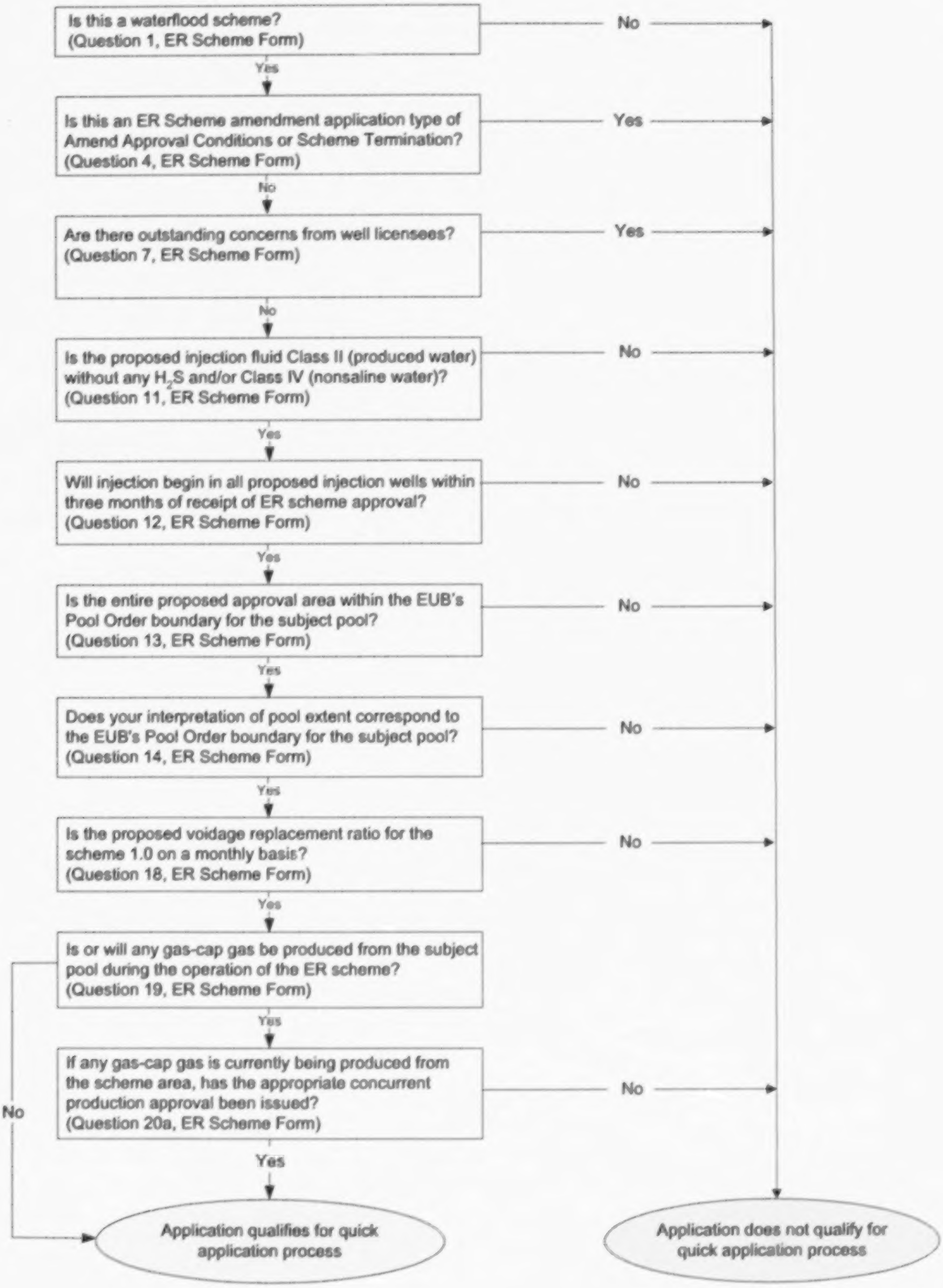
Is this a waterflood scheme? (Question 1, ER Scheme Form)
No
Yes
Is this an ER Scheme amendment application type of Amend Approval Conditions or Scheme Termination? (Question 4, ER Scheme Form)
Yes
No
Are there outstanding concerns from well licensees? (Question 7, ER Scheme Form)
Yes
No
Is the proposed injection fluid Class II (produced water) without any H2S and/or Class IV (nonsaline water)? (Question 11, ER Scheme Form)
No
Yes
Will injection begin in all proposed injection wells within three months of receipt of ER scheme approval? (Question 12, ER Scheme Form)
No
Yes
Is the entire proposed approval area within the EUB's Pool Order boundary for the subject pool? (Question 13, ER Scheme Form)
No
Yes
Does your interpretation of pool extent correspond to the EUB's Pool Order boundary for the subject pool? (Question 14, ER Scheme Form)
No
Yes
Is the proposed voidage replacement ratio for the scheme 1.0 on a monthly basis? (Question 18, ER Scheme Form)
No
Yes
Is or will any gas-cap gas be produced from the subject pool during the operation of the ER scheme? (Question 19, ER Scheme Form)
No
Yes
If any gas-cap gas is currently being produced from the scheme area, has the appropriate concurrent production approval been issued? (Question 20a, ER Scheme Form)
No
Yes
Application qualifies for quick application process
Application does not qualify for quick application process

Figure 2.1. Decision Tree for Quick Enhanced Recovery Application Process

The ERCB will issue its disposition on ER scheme applications electronically, with the disposition being available for viewing through IAR Query for 30 days after the disposition of the application. IAR Query is accessible via the Applications page on the ERCB's Web site. It will take the ERCB longer to issue a decision on nonelectronic applications.

If ER operations involve any hydrogen sulphide (H_2S) injection and an emergency response plan (ERP) is required, the ERP must be approved prior to the ER scheme approval being issued. ERPs are approved and reviewed for compliance by the ERCB Operations Group. See *Directive 071: Emergency Preparedness and Response Requirements for the Upstream Petroleum Industry* for further details on emergency response planning. In addition, if an injection fluid contains H_2S, all pipelines and facilities associated with the scheme must be approved for the appropriate sour service as per *Directive 056: Energy Development Applications and Schedules*.

Pool delineation differences that are pertinent to the ER scheme design must be resolved by a separate pool delineation application, in accordance with Section 2.5 of this directive, prior to the submission of an ER scheme application. An exception may be if the proposed approval area is larger than the Pool Order boundary due to wells not yet evaluated by the ERCB.

2.1.1.3 Other Issues

A) Allowable Administration

For oil pools on maximum rate limitation (MRL) administration, upon approval of a new ER scheme or ER scheme amendment, good production practice (GPP) will normally be granted to the wells within the approval area provided that injection will begin within three months of the approval date. If injection is not scheduled to begin within three months, the ERCB may decide to grant GPP after written notification to the ERCB that injection has commenced. Wells outside of the approval area will normally remain on MRL.

If granted, with the condition that injection will begin within three months, GPP will be effective concurrent with the ER approval. Wells must not produce above their MRL prior to GPP being granted. With the granting of GPP before confirmation that injection has commenced, the ERCB expects operators to prudently produce their wells pending the successful implementation of ER.

For oil pools on GPP administration, upon approval of a new ER scheme or ER scheme amendment, GPP will normally be retained for wells within the approval area. For wells outside the ER approval area, the ERCB may require the well licensees to address ER feasibility and the appropriateness of continued GPP status.

B) Wellbore Integrity and Completion Requirements

Wellbore integrity requirements, detailed in ERCB *Directive 051: Injection and Disposal Wells—Well Classifications, Completions, Logging, and Testing Requirements*, will now be administrated through the ERCB Operations Group and will occur outside of the ER application process. All submissions relating to the requirements of *Directive 051* should be sent to the ERCB Operations Group for review and approval. The ER application disposition documents (approval and letter) will no longer incorporate the *Directive 051* approval. The *Directive 051* requirement documents may be submitted either in advance of or following submission of the ER scheme application, but injection may not begin until after written confirmation that both the ER scheme application has been approved and the *Directive 051* requirements have been met.

The ERCB specifies a deadline for injection to begin in the ER approval. If you cannot meet the *Directive 051* requirements and begin injection prior to the specified deadline, you must submit an ER amendment application (Amend Approval Conditions) addressing the anticipated commencement of injection and the reason(s) for the delay. If the *Directive 051* requirements are not met prior to the specified injection deadline, the ERCB may rescind the approval or portion thereof.

C) Reserves

The ERCB sets ER reserves outside of the ER scheme application review process. A nominal level of reserves information is required in all ER scheme applications, with more detail possibly being required for applications involving more complex ER processes. The processing of ER scheme applications will not be delayed to conduct a detailed review of reserves, but ER reserves will be set as early as possible following approval of an ER scheme. Approval holders may be required to provide additional information regarding reserves outside the application review process.

Reserves changes are not communicated directly to companies, but ERCB reserves values are available upon request through Information Services. Any changes to the rate administration of wells due to reserve changes are reflected in the monthly MRL order.

D) Use of Nonsaline Water

The ERCB supports the water management objectives of Alberta's *Water for Life: Alberta's Strategy for Sustainability* and the reduction plans outlined in the *Advisory Committee on Water Use Practice and Policy Final Report*. In this regard, applicants proposing to use nonsaline water in an ER scheme must obtain prior approval from Alberta Environment (AENV) under the *Water Act* for the diversion of the nonsaline water. This approval must be obtained before submitting an application for an ER scheme to the ERCB. AENV requires applicants for water diversion to fully investigate alternatives and submit evidence showing that there are no practical alternative saline water sources. For information on a water diversion application, please contact the regional offices of AENV.

2.1.2 ERCB Requirements and Expectations for ER Schemes

The ERCB's objective in regulating ER schemes is to ensure that hydrocarbon recovery is optimized. In meeting this objective, the ERCB must also ensure that scheme operations are conducted in a safe manner that is in the best interest of the public, protects the environment, and is equitable to other well licensees.

2.1.2.1 Scheme Requirements

Scheme requirements are those rules that must be met and against which the ERCB will take enforcement action in cases of noncompliance. In addition to all other requirements of the *Oil and Gas Conservation Act* and *Regulations*, the following are some specific requirements for all ER schemes:

- The approval holder is responsible for the successful operation of an ER scheme.
- Approval holders must comply with all conditions of ER approvals.
- The holder of the ER approval must be the current operator of the scheme.
- Injection must not begin in a well until after written confirmation that both the ER scheme application has been approved and *Directive 051* requirements have been met.
- Gas-cap gas production requires ERCB approval for concurrent production.
- The type of ER scheme (e.g., waterflood, miscible flood, gas cycling) must be selected to maximize recovery.
- The type of injection fluid must be selected to maximize hydrocarbon recovery.
- All ER schemes must be operated in a manner that optimizes hydrocarbon recovery.
- The injection fluid must be compatible with the reservoir rock and reservoir fluid.
- The supply of injection fluid must be capable of maintaining the specified scheme voidage replacement.
- Injection wells and injection intervals must be located in such a manner that optimizes both areal and vertical sweep efficiency.
- The proposed approval area must reflect the area that will be effectively swept by the injection wells and must conform to the ERCB-approved spacing.
- The approval will list only existing injection well locations, not those planned at some future date.
- The holder of an ER approval must comply with *Directive 051*. Injection pressures must remain below the approved maximum wellhead injection pressure at all times.
- Gas must be conserved in accordance with *Directive 060: Upstream Petroleum Industry Flaring Guide*.
- If an ERP is required for the injection of H_2S, an up-to-date ERCB-approved ERP must be in place.
- The ER scheme approval area will not extend beyond the ERCB's Pool Order boundary for the subject pool.

2.1.2.2 Scheme Expectations

Although optimal operating practices may vary for each reservoir, there are fundamental principles and practices that the ERCB expects to be followed, in addition to the above-noted requirements, for all ER schemes. ERCB expectations on how ER schemes should be assessed, designed, implemented, and operated are described below.

A) Assessment Stage

- For all pools, including those that are on GPP, the feasibility of ER should be reviewed on an ongoing basis.
- For retrograde gas condensate pools, the feasibility of gas cycling should be evaluated before reaching the dew point pressure in order to maximize recovery.
- Well licensees should collect the appropriate reservoir data necessary to accurately assess ER potential.
- ER should normally be evaluated and, if feasible, implemented in oil pools prior to production of the gas cap.

- Pool delineation should be well understood prior to designing and implementing an ER scheme.
- The applicant should have a good understanding of the reservoir and fluid properties prior to designing the ER scheme.

B) Design Stage

- In waterfloods, produced water should be reinjected.
- Production wells that are second or third line offset from injection wells should be included in the proposed scheme only when it is anticipated that the proposed injection wells will be able to provide adequate sweep and pressure support.

C) Implementation Stage

- Injection operations should be initiated at the optimal time. Injection should begin before the reservoir pressure drops below the bubble point pressure in oil pools or the dew point pressure in the case of retrograde gas condensate pools.
- Injection operations in all approved injection wells should begin as soon as possible. In most cases, the ERCB will specify a deadline for the commencement of injection of three months from the date of the approval or amendment.

D) Operations

- If there are multiple well licensees within the approval area, the approval holder is expected to coordinate the scheme operations to ensure that maximum recovery is attained.
- All well licensees in the approval area are expected to adhere to the approval conditions.
- Well licensees should collect the appropriate reservoir data necessary to accurately assess an ER scheme and optimize scheme performance.
- Alternatives to nonsaline water injection should be assessed on an ongoing basis.
- The entire approval area should have a uniform voidage replacement and pressure distribution.
- Where feasible and appropriate, the ER scheme should be operated at a reservoir pressure close to the bubble point pressure or dew point pressure.
- To provide operating flexibility, an ER approval does not need to be amended to remove wells that have ceased injection.
- Well licensees are expected to prudently produce their wells pending the successful implementation of ER.
- ER schemes should be monitored and adjustments or changes made to ensure optimum recovery.

2.1.3 Requirements for ER Scheme Applications

2.1.3.1 Requirements That Must Be Met Before an ER Application May Be Submitted

An ER application may be submitted to the ERCB once the following requirements have been met:

- The primary applicant[*] has obtained the right to represent all well licensees within the proposed approval area.
- The primary applicant has notified all well licensees in accordance with the requirements in Section 2.1.3.2.
- The proposed injection wells have been drilled.
- The source of the proposed injection fluid has been secured.
- There are no differences between the applicant's and the ERCB's interpretation of pool delineation that are pertinent to the ER scheme.
- For a scheme amendment, the primary applicant is the approval holder.

2.1.3.2 Notification Requirements for ER Scheme Applications

An applicant must provide proper notification, including scheme details such as approval area, type of ER scheme, and injection well locations, to all well licensees in accordance with the following requirements. Notification must be provided a minimum of 10 days prior to submission of the application to the ERCB. Failure to complete notification as required may result in an application being closed without being processed.

Minimum Notification Requirements

Applicants for enhanced oil recovery (EOR) schemes (new and amendment) must notify, as a minimum,

- licensees of wells that are completed in the pool and are within the proposed approval area,
- licensees of wells that are completed in the pool and are within 800 metres (m) of the proposed injection well(s), and
- for new EOR schemes, licensees of wells that are completed in the pool and are within a quarter section of the proposed approval area.

Applicants for gas cycling schemes (new and amendment) must notify, as a minimum,

- licensees of wells that are completed in the pool and are within the proposed approval area, and
- for new gas cycling schemes, well licensees that are within a section of the proposed approval area.

Special circumstances, such as pressure communication between pools through a common aquifer, may require notification beyond the minimum requirements.

Licensees of abandoned wells do not need to be notified.

The ERCB expects well licensees to act in the best interest of all parties with an interest in a well, including lessees and lessors, particularly in cases of mixed ownership within the proposed approval area.

Applicants must retain the list of well licensees notified regarding the proposed scheme/amendment, the notification document, the date of notification, and any responses or comments received. This information is not required to be submitted as part of the ER application unless there are unresolved licensee concerns. In this case, a Licensee Concerns attachment must be included.

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[*] A primary applicant is a company, other than a consulting company, that is submitting an application to the ERCB.

2.1.3.3 Forms and Attachments Required for ER Scheme Applications

A) Summary of Required Application Documents

All ER scheme applications must include

- Resources Applications Schedule 1
- ER Scheme application form (Appendix F),
- Attachments
  - Application
  - Approval Area Map
  - Pressure-Volume-Temperature (PVT) Data
  - Reserves Data
  - Licensee Concerns (if there are any unresolved concerns)
  - Isopach Map (for new ER schemes and significant area amendments)
  - Well Log(s) (for new ER schemes and significant area amendments)
  - Pressure Data and Interpretation (for new ER schemes and significant area amendments)
  - Structure Map (for new gas cycling schemes)
  - Miscellaneous (additional information to support the request)

Further explanation on the ER Scheme application form and attachments is provided in the following sections (B) and (C).

B) Explanatory Notes for ER Scheme Application Form Questions

The ER Scheme application form is in Appendix F. The numbering below corresponds to the questions on the form.

Application Type

1) Type of ER scheme being proposed or amended:

Only one type of ER scheme may be selected. Although schemes may have multiple types of injection fluid, there generally is a predominant recovery mechanism or scheme type. For example, a scheme with water-alternating-gas (WAG) injection is a miscible scheme even though solvent, water, and gas would be injected during the scheme's life.

If you choose Other, you must include a description of the ER process and supporting technical documents/papers discussing the method in the application.

2) Is this application for a new ER scheme or an amendment to an existing ER scheme approval?

If an ERCB approval for ER does not exist for the subject scheme, select New.

If an ERCB approval for ER exists for the subject scheme, select Amendment.

3) *What is the existing ERCB approval number proposed for amendment?*

If the application is for an amendment to an existing ER scheme approval, enter the current approval number without alpha characters.

4) *Type of Amendment:*

If the application is for an amendment to an existing ER scheme approval, the type of amendment must be selected. Multiple amendment types may be selected, with the exception of "Scheme termination," which must be a singular ER scheme amendment type.

Add injection well location(s): Select this box if you are requesting approval to add one or more injection well locations to the approval.

Amend approval area: Select this box if you are requesting a change to the current approval area (shown in the appendix to the approval). The proposed approval area should reflect the area that will be effectively swept by the injection wells and should conform to the ERCB-approved spacing.

*Amend approval conditions: S*elect this box if you are requesting to change a condition of the approval. For example, this could include changes to the minimum operating pressure or voidage replacement requirements, but not a change to the holder of the approval.

Scheme termination: Select this box if you are requesting approval to rescind the ER approval.

Ownership and Notification Information

5) *The primary applicant must*
   a) *be the proposed approval holder for a new scheme or the current approval holder for an existing scheme, and*
   b) *represent all well licensees in the proposed approval area.*

   Have these requirements been met?

YES means that both of these requirements have been met and the primary applicant accepts responsibility for compliance with all conditions of the approval.

NO means that one or both of these requirements have not been met, and as a consequence the application may not be submitted. Any request to change the approval holder must be made in accordance with Unit 5 of this directive.

6) *An ER scheme application cannot be submitted until notification of all well licensees has been completed in accordance with* Directive 065.

   Has notification been completed in accordance with Directive 065?

YES means that the notification requirements specified in Section 2.1.3.2 have been met.

NO means that these requirements have not been met. An ER scheme application may not be submitted until these requirements have been met.

7) *Are there outstanding concerns from well licensees? If yes, the Licensee Concerns attachment must be submitted as part of the application, in accordance with* Directive 065.

YES means that there are unresolved concerns or objections from one or more of the well licensees that were notified of the application. The information required in a Licensee Concerns attachment is identified in Section 2.1.3.3(C) of this directive.

NO means that there are no known unresolved well licensee concerns from any of the well licensees that were notified of the application.

Proposed Injection Well Locations and Injection Intervals

This section must only be completed for new ER schemes and amendment types requesting to add injection well location(s).

8) *An ER scheme application cannot be submitted unless the proposed injection wells have been drilled.*

   Have the proposed injection wells been drilled?

YES means that all the proposed injection wells have been drilled.

NO means that all the proposed injection wells have not been drilled. The ERCB is not prepared to accept an ER application when the proposed injectors are not drilled because of the potential this creates for changes to the scheme details (commencement of injection date, bottomhole location of injector, and the unconfirmed presence and quality of the reservoir).

9) *An ER scheme application cannot be submitted unless the source of the proposed injection fluid has been secured.*

   Has the source of the proposed injection fluid been secured?

YES means that the supply of injection fluid is secured and will be available for use by the proposed injection date.

If nonsaline water is to be used for injection, you must have a valid water diversion permit from Alberta Environment. The water diversion permit number must be provided in the Application attachment.

NO means that the injection fluid source has not been secured. The ERCB is not prepared to accept an ER application when the injection fluid has not been secured because of the potential for delays in the commencement of injection.

10) Provide the following for the proposed injection well locations:

Well Licence Number: The well licence number issued by the ERCB for the proposed injection well.

Unique Well Identifier (UWI): the UWI (LE/LSD-SEC-TWP-RGEWMER/ES) associated with the Well Licence Number. The full unique well identifier is listed in the approval; it is important to enter the correct identifier. If the event sequence is not known or available, enter the "0" event and note this uncertainty in the Application attachment.

Injection Interval: The top and base depth of the injection interval.

Porosity Interval: The porosity top and porosity base depth of the reservoir proposed for injection.

Fluid Interface: The current gas/oil and oil/water depths (if applicable) in the reservoir proposed for injection. These depths may be measured or estimated.

11) What type of injection fluid, as identified by Directive 051, *will be used?*

Multiple injection fluids may be selected. Further descriptions of the injection classes are in *Directive 051*.

11a) If an injection fluid contains H_2S and an emergency response plan (ERP) is required, the ERCB must ensure that an up-to-date ERP is in place prior to its decision on the application.

Is an ERCB-approved ERP incorporating the proposed scheme in place?

If no, a discussion addressing the status of the ERP must be included in the Application attachment, in accordance with Directive 065.

There are additional environmental and safety concerns that need to be addressed when the injection fluid contains any H_2S. Therefore, the ERCB must ensure that the need for the ERP has been addressed and if one is required that the ERCB Operations Group has approved an ERP that encompasses the proposed scheme prior to making a decision on an application.

YES means that an ERCB-approved ERP incorporating the proposed scheme is in place.

NO means that either an ERCB-approved ERP incorporating the proposed scheme is required but not in place or that an ERP is not required. For either situation, an explanation must be provided.

ERPs should be forwarded directly to the ERCB Operations Group for review. See *Directive 071* for further details on emergency response planning.

12) Will injection commence in all proposed injection wells within three months of receipt of approval?

If no, a discussion addressing the anticipated commencement of injection and the reason for the delay must be included in the Application attachment, in accordance with Directive 065.

YES means that injection will begin within three months of the date of approval. This commencement of injection date will be a condition of the approval.

NO means that injection will not begin within three months of receipt of approval. Provide reasons for the delay in the commencement of the injection date beyond the standard three-month period. If injection will not begin within three months, the ERCB will generally not grant GPP at the time of the ER approval due to conservation concerns. The ERCB may decide to grant GPP after written notification to the ERCB that injection has begun.

Proposed Approval Area

This section must only be completed for new ER schemes and amendment types requesting to amend the approval area.

13) Is the entire proposed approval area within the ERCB's Pool Order boundary for the subject pool?

YES means that the entire proposed approval area is within the ERCB's current Pool Order boundary for the subject pool.

NO means that the proposed approval area extends beyond the ERCB's current Pool Order boundary for the subject pool. The ERCB cannot approve ER approval areas larger than the Pool Order boundary. Differences in pool delineation should be addressed prior to submission of the ER application. Note that the approval area will not include injectors without hydrocarbon pay, but such injectors may be listed in the approval.

The ERCB's Pool Order boundaries are on the ERCB's Web site under the Board Order System (BOS) at www.ercb.ca.

14) Does your interpretation of pool extent correspond to the ERCB's Pool Order boundary for the subject pool?

YES means that your interpretation of pool extent coincides with the area identified by the ERCB's current Pool Order boundary for the subject pool.

NO means that your interpretation of pool extent does not coincide with the area identified by the ERCB's current Pool Order boundary for the subject pool.

The ERCB's Pool Order boundaries reflect quarter section for wells with oil pay and one section for wells with gas pay.

15) Is the difference in pool delineation interpretation pertinent to the proposed ER scheme, in accordance with Directive 065*?*

Provide a discussion of the difference in pool delineation and the pertinence to the proposed ER scheme in the Application attachment, in accordance with Directive 065.

A difference in pool delineation is considered pertinent if it affects any of the following aspects of the proposed ER scheme: approval area, approval conditions, notification, or approved injection wells.

Pool delineation is very important to the ERCB's review of any ER scheme. The assessment of the effectiveness of the proposed scheme relative to the optimal depletion strategy for the entire pool requires that overall pool delineation be known. Also, accurate pool delineation is necessary to allow for the identification of possible equity concerns involved with the proposed ER scheme.

YES means that your pool interpretation differs from that of the ERCB in a manner that could impact the ER approval. Significant differences in pool delineation must be dealt with in advance of making an ER scheme application. However, an exception may be where the proposed approval area is larger than the Pool Order boundary due to wells not yet being evaluated by the ERCB.

NO means that your pool interpretation differs from that of the ERCB in a manner that does not impact the ER approval. For example, the recognized differences are significantly outside of the proposed approval area.

If the proposed approval area extends beyond the ERCB's Pool Order boundary for the subject pool or your interpretation of pool extent does not coincide with the ERCB's Pool Order boundary for the subject pool, an explanation of the difference and a discussion of why this difference is not pertinent to the proposed ER scheme must be provided.

Scheme Details

16) Is the scheme area currently administered under good production practice (GPP)?

YES means that all of the wells within the proposed approval area have been granted GPP.

NO means that some or all of the wells within the proposed approval area are subject to a prescribed maximum rate limitation (MRL) or that the proposed scheme is in a gas pool.

A copy of the most recent MRL Order can be found on the ERCB's Web site.

17) Will produced gas from the ER scheme area be conserved, in accordance with Directive 060 *requirements?*

The ERCB expects that gas conservation in accordance with *Directive 060* is occurring. See *Directive 060* for further information.

18) What is the proposed voidage replacement ratio (VRR), on a monthly basis, for the scheme?

> *The ERCB normally specifies a VRR of 1.0 to fully maintain reservoir pressure. If the VRR will not be 1.0, provide a technical justification in the Application attachment, in accordance with* Directive 065.

Specify the proposed monthly VRR for the scheme. The VRR should reflect the injection into and production from the total scheme area. Technical justification for a VRR other than 1.0 must be provided, along with the reason(s) for the over- or under-injection and its impact on scheme recovery. The ERCB will normally specify a VRR as a condition of the approval.

19) Is or will any gas-cap gas be produced from the subject pool during the operation of the ER Scheme?

If yes, include a discussion on the potential for fluid migration into the gas cap in the Application attachment, in accordance with Directive 065.

YES means that gas-cap gas is or will be produced from the pool, either within or outside of the scheme area, during the period that the ER scheme is operational.

If any gas-cap gas is or will be produced from the subject pool during the operations of the ER scheme, provide a discussion on the potential for fluid migration from the scheme into the gas-cap and pressure depletion in the scheme due to gas-cap gas production. If potential for fluid migration or pressure depletion is identified, the discussion should include the impact on ultimate hydrocarbon recovery.

NO means either that there is no associated gas cap in the pool or that the associated gas cap will not be produced during the period that the ER scheme is operational.

20) Is gas-cap gas currently being produced from the scheme area?

YES means that an associated gas cap is present in the pool and this gas is currently being produced from the scheme.

NO means that an associated gas cap is present in the pool but this gas is not currently being produced from the scheme.

20a) Has the appropriate concurrent production (CCP) approval been issued?

If Question 20 is answered yes, gas-cap gas is currently being produced from the scheme area and this question must be answered.

YES means that the appropriate form of concurrent production that encompasses the current gas-cap gas production has been approved by the ERCB. The CCP approval details are listed in the ERCB's MRL Order.

NO means that the current gas-cap gas production has not been approved by the ERCB.

20b) An application for CCP is required. Has an application for CCP been registered?

If Question 20a is answered no, the current gas-cap gas production has not been approved by the ERCB and this question must be answered.

YES means that an application for CCP has been registered with the ERCB.

NO means that an application for CCP has not yet been registered with the ERCB. Unauthorized CCP is not permitted; an application for CCP is required pursuant to Section 39(1)(f) of the *Oil and Gas Conservation Act* and Section 2.4 of this directive.

20c) If yes, provide the CCP application number.

If Question 20b is answered yes, an application for CPP has been registered with the ERCB and this question must be answered.

If an application for CCP has been registered, enter the ERCB application number. Information details on applications registered with the ERCB are on the ERCB's Web site.

C) Explanatory Notes for ER Scheme Application Attachments

Application Attachment

A text attachment providing a description of the proposed scheme that includes:

1) the proposed injection pattern,

2) the expected sweep efficiencies (e.g., vertical, areal)

3) the displacement type (e.g., bottom water drive, horizontal),

4) the measures taken to prevent channelling and to maximize the swept reservoir volume,

5) the proposed date of commencement of injection,

6) the approximate date when the proposed VRR will be achieved, and

7) the type, composition, and source of the injection fluid, including chase gas for miscible floods. For changing injection fluid compositions, provide the anticipated range of compositions; for nonsaline water injection, provide the water diversion permit number.

8) If an injection fluid contains any H_2S and an ERP is required, a statement that an up-to-date ERP incorporating the proposed scheme is in place or a discussion addressing the status of the ERP update. If an ERCB-approved ERP is not required for the proposed scheme as per *Directive 071* requirements, an explanation of why an ERP is not required.

9) If all of the proposed injection wells will not begin injection within three months of the approval date, include a discussion addressing the anticipated commencement of injection for each injection well and the reason for the delay.

   On-injection dates of up to six months from the date of approval may be considered by the ERCB with sufficient justification, but the ERCB will review and decide on each such application.

10) If your interpretation of pool delineation is different than the ERCB's interpretation, as reflected by the current Pool Order boundary, include a discussion of the difference in pool delineation and why the difference is not pertinent to the proposed ER scheme. In cases where wells in the proposed scheme area have not yet been evaluated by the ERCB, the wells requiring review should be identified.

11) If the proposed Voidage Replacement Ratio (VRR) is not 1.0 on a monthly basis, provide technical justification for a VRR other than 1.0, including the reason(s) for the over- or under-injection and its impact on scheme recovery. For example, if partial pressure maintenance is provided by an associated aquifer, include detailed analysis to show that the proposed VRR in combination with the aquifer will maintain reservoir pressure.

12) If any gas-cap gas is or will be produced from the subject pool during the operations of the ER scheme, provide a discussion on the potential for fluid migration from the scheme into the gas-cap and pressure depletion in the scheme due to gas-cap gas production. If potential for fluid migration or pressure depletion is identified, the discussion should include the impact on ultimate hydrocarbon recovery.

13) If any gas-cap gas is currently being produced from the proposed scheme area and the appropriate concurrent production approval does not exist, provide a discussion of your plans to submit a concurrent production application.

Approval Area Map Attachment

Map(s) showing

1) the ERCB's current Pool Order boundary for the subject pool (http://www.ercb.ca/portal/server.pt/gateway/PTARGS_0_0_269_231_0_43/http%3B/extContent/publishedcontent/publish/eub_home/industry_zone/industry_activity_and_data/bos___board_order_system/),

2) the location and current status (indicated by well symbols) of each well
   - within the proposed approval area and
   - within the notification area specified in Section 2.1.3.2,

   with wells completed in the pool highlighted,

3) the outline of other existing ER recovery scheme approval areas within the pool that offset the subject scheme, and

4) for a **new ER scheme**, include the applied-for approval area, and for an **ER amendment application,** include the current approval area and any proposed areas of amendment and the zero edge of the pool.

The proposed approval area must reflect the area anticipated to be swept by the scheme injectors and should conform to the ERCB-approved drilling spacing units.

For clarity, the information may be provided on separate maps.

For very large pools, the map should focus on the region in and surrounding the scheme area.

For a new scheme, the net oil/gas pay isopach map(s) must be provided as a separate attachment. For scheme amendments, the pool zero edge in the region of the proposed scheme area must be provided.

PVT Data Attachment

Pressure-volume-temperature (PVT) properties, including

1) the initial reservoir pressure,
2) the proposed operating pressure of the scheme,
3) the current average reservoir pressure within the scheme area,
4) the saturation (bubble point) pressure,
5) the reservoir temperature,

6) the B_{oi}, B_{gi} (if applicable), R_{si}, and B_{wi} values,
7) the B_o, B_g, R_s, and B_w values at the current average reservoir pressure within the scheme area, and
8) the source of the PVT data.

For gas cycling schemes, substitute the dew point pressure for item (4), and the full constant volume depletion analysis of the reservoir fluid for items (6) and (7).

All data must be in metric units.

Along with the stage of reserves recovery, the value of the bubble point or dew point relative to the current and proposed operating pressures is an important consideration when evaluating an ER scheme.

Reserves Data Attachment

Estimates of the oil and gas reserves, including

1) the initial oil and gas volumes in place for the ER scheme area,
2) the oil and gas recovery factors under the existing depletion mechanism and under the proposed ER scheme,
3) the recoverable oil and gas reserves for the scheme area,
4) the reservoir area, average net pay, average porosity, and average water saturation for oil and gas in the scheme area,
5) a description of the methods used in determining the estimates for (1) and (2) above (e.g., material balance, volumetric analysis, model study, a comparison of analog pools, and sweep and displacement efficiencies), and
6) for gas cycling schemes, the initial propane, butane, and condensate in place converted to liquid volumes.

A fundamental service that the ERCB provides to all stakeholders is maintaining reserve estimates for all pools in Alberta.

A nominal level of reserves information is required in ER scheme applications, and more detail may be required for applications involving more complex ER processes. As well, additional information may be requested during the application review, after approval, or during a future audit.

Licensee Concerns Attachment

If there are any unresolved concerns from a well licensee, provide an attachment that includes the following:

1) contact information for the well licensee that has unresolved concerns/objections,
2) a copy of the notification letter provided to the well licensees,
3) a list of any other documents distributed,
4) a copy of written concerns and objections received, or if not available, a summary of issues,
5) a chronology of any discussions conducted with the well licensee(s),
6) a discussion of how the applicant would like the ERCB to proceed with the application, and

7) any steps taken to mitigate the unresolved concerns and objections and the applicant's response to the concerns.

Isopach Map Attachment (for new ER schemes and significant area amendments)

An isopach map of net oil and/or gas pay showing

1) location of the initial fluid interfaces (gas-oil, gas-water, oil-water), and
2) location and current status (indicated by well symbols) of each well within and offsetting the proposed approval area.

The ERCB requires the geological extent and hydrocarbon pay thickness of a pool, any fluid interfaces, and well control with statuses to assess how the proposed scheme relates to optimum pool depletion, other existing schemes, and potential pool delineation and equity issues.

For very large pools, the map should focus on the region in and surrounding the scheme area.

Well Log(s) Attachment (for new ER schemes and significant area amendments)

An interpreted and annotated log cross-section or representative well log(s) showing

1) stratigraphic interpretation of the zone(s) of interest,
2) interpretation of fluid interfaces (original and current, if applicable),
3) completion and treatments to the wellbore(s), with dates,
4) cumulative production,
5) finished drilling date and kelly bushing (KB) elevation, and
6) the scale of the log readings.

This cross-section may be presented in a number of ways—as one representative well log, several well logs, or a detailed cross-section of the entire pool—depending on the complexity and heterogeneity of the pool. The information on this cross-section assists in establishing the vertical continuity within the pool and the overall quality of the pool.

Pressure Data and Interpretation Attachment (for new ER schemes and significant area amendments)

Reservoir pressure data, including

1) measured or estimated reservoir pressures for the scheme area,
2) the source of the data, and
3) a discussion of how the pressure data relates to and supports the scheme operations.

The applicant must include all pressure data available for scheme wells. The data may be presented in various formats, such as a pressure-time plot, an isochronal map, or a table illustrating the pressures for the scheme wells. Pressure data should be corrected to the ERCB-established pool datum.

All pressure data must be in metric units.

Reservoir pressure data are a key component to ensure the success and optimal operation of ER schemes. Taking timely and representative reservoir pressure measurements assures that the necessary information is available to help monitor and optimize scheme performance. All new ER schemes will be added to the annual pressure survey schedule unless otherwise stated.

Structure Map Attachment (requirement for new gas cycling schemes)

A structure map of the subject pool clearly identifying interpreted fluid interfaces (current and original, if applicable), stratigraphic horizon, and contoured surface (porosity top or formation top).

If the proposed ER scheme is for a gas cycling scheme or an ER scheme where vertical displacement is important to evaluating the scheme design, a structure contour map must be provided.

D) Additional Requirements for ER Scheme Amendment Applications

The requirements listed in this section are supplemental to the mandatory requirements and vary according to the type of amendment.

Add Injection Well Location(s)

Provide a technical explanation of why the additional injection location(s) are required and how they are consistent with the optimal depletion strategy to ensure that hydrocarbon recovery is maximized from the scheme area.

Amend Approval Area

Provide a written description of and technical justification for the proposed changes to the approval area. For a significant expansion to the area of an existing scheme, the ERCB requires the isopach map, well log(s), and pressure data and interpretation attachments.

Amend Approval Conditions

Provide the specific details of and technical justification for the proposed changes to the approval conditions.

Scheme Termination

An application to rescind an ER approval is required to terminate an ER scheme. Generally, termination of the scheme involves ceasing all injection.

An application to rescind an ER approval must include

1) a discussion of the reason(s) for termination of the scheme, including how the pressure and production performance justifies the request for termination;
2) a detailed economic analyses to show that continued injection is uneconomic—the ERCB may request further economic justification for scheme termination in certain cases;
3) a discussion of other scenarios, apart from ceasing injection completely, that were considered—for example, partial pressure maintenance, well recompletions, or workovers;
4) a discussion of the future depletion strategy for the approval area and the remaining recoverable reserves; and

5) a discussion of the success of the ER scheme, including the details of the actual incremental volumes by recovery mechanism (e.g., primary, waterflood, gas cycling, miscible flood).

E) Additional Requirements for Miscible Flood Scheme Applications

The requirements listed in this section are supplemental to the mandatory requirements and are specific to new miscible flood schemes. Amendments to existing miscible flood schemes should only address the requirements necessary to justify the request.

An application for a new miscible flood scheme must include

1) proof of miscibility with the reservoir oil, which usually requires slim tube or rising-bubble tests over a range of injection fluid compositions and/or pressures to establish the point or boundary of miscibility;

2) the proposed miscibility conditions, as appropriate, from the following:

    a) the minimum miscibility pressure (MMP) at the proposed composition of the injection fluid:

        The MMP is the lowest pressure for which the injection fluid can develop miscibility through a multicontact process with the given reservoir oil at reservoir temperature. To maximize oil recovery, the ERCB may specify a minimum operating pressure (MOP) in the approval. The specified MOP will usually be nominally higher than the MMP to incorporate a safety factor for miscibility.

    b) a correlation of injection fluid composition versus operating pressure,

    c) the minimum pseudo-critical temperature of the injection fluid and MOP,

    d) the minimum C2+ content of the injected fluid and MOP, and

    e) other conditions to ensure miscibility;

3) for water alternating gas (WAG) schemes, the proposed WAG ratio target and range and WAG cycle, along with the technical justification; and

4) the methodologies proposed to be used to determine when injection fluid breakthrough occurs and to calculate the volumes of injection fluid breakthrough. Fluid sampling and analysis for miscible flood (MF) schemes must follow the requirements specified in *Informational Letter (IL) 92-5: Reduced Fluid Sampling and Analysis for Hydrocarbon Miscible Flood Schemes*, unless otherwise stated in the approval.

F) Additional Requirements for Gas Cycling Scheme Applications

If an operator considers gas cycling appropriate, an application for an ER scheme must be submitted. Amendments to an existing gas cycling scheme should only address the requirements necessary to justify the request. In addition to the requirements for an application for a new ER scheme, an application for a new gas cycling scheme must include

1) the proposed rate of cycling and the cycling period before blowdown commences with supporting technical and economic data;

2) the following historical and forecast annual production under various depletion strategies (including primary depletion, partial gas cycling, and full gas cycling):
   a) raw gas,
   b) sales gas,
   c) individual liquid coproducts, and
   d) sulphur;

   This performance information for gas cycling schemes should provide the basis for the economic evaluation used in determining the optimum depletion strategy.

3) the forecast annual gas injection showing the portion of make-up gas versus reinjected gas;

4) the composition of the current gas-cap gas, and the average composition of the injected gas on an annual basis;

5) the estimated liquid and sales gas recovery by the various depletion strategies compared to primary depletion; and

6) economic evaluation used to determine the optimum depletion strategy.

The quantification of natural gas liquids carried in the gas cap is of primary importance to the feasibility of the scheme.

2.1.4 ER Related Processes

2.1.4.1 Reporting Requirements

Progress reports for most ER schemes (waterfloods and immiscible gas floods) were eliminated in ERCB *IL 94-13: ERCB Progress Report Requirements—Conventional Enhanced Recovery Schemes*. Reporting is still required in the following situations for ER schemes:

- performance presentations and annual data submissions for active miscible flood schemes, in accordance with ERCB *IL 96-2: Progress Report Requirements for Miscible Flood Schemes*,
- progress reports and/or performance presentations for gas cycling schemes,
- reporting required as a condition of an ERCB approval or letter, and
- any reporting required as follow-up to ERCB audit and surveillance processes, including reserve estimates.

2.1.4.2 Audit, Surveillance, and Enforcement

The ERCB will audit all new ER schemes and selected scheme amendments about six months after approval issuance. These audits will be conducted to

- confirm compliance with approval conditions,
- verify that the requirements of *Directive 051* have been met,

- review scheme performance (actual versus predicted) to identify any issues, and
- validate data integrity.

If issues arise, the ERCB may request additional information or clarification from the approval holder, take appropriate enforcement action and require corrective measures necessary to protect the oil and gas resource, equity, safety, and the environment.

In addition to the six-month audit, the ERCB will conduct surveillance on all provincial ER schemes on an ongoing basis. Random or targeted reviews may be conducted to ensure that compliance is met and that performance is consistent with expectations. If compliance or performance issues are identified, the ERCB will take appropriate enforcement action and require the approval holder to implement corrective measures.

The ERCB's current enforcement actions regarding ER schemes are set out in *Directive 019: ERCB Compliance Assurance—Enforcement*.

2.2 Enhanced Oil Recovery Project

[Rescinded]

2.3 Enhanced Recovery Recognition and Good Production Practice for Enhanced and Oil Recovery Schemes

[Rescinded]

2.4 Application for Concurrent Production

2.4.1 Background

Concurrent production (CCP) is defined as the production of an oil accumulation and its associated gas cap at the same time. Section 39(1)(e) of the *Oil and Gas Conservation Act* requires that no CCP scheme may proceed unless approved by the ERCB. CCP is a poolwide depletion decision requiring equitable treatment of all participants with productive wells.

2.4.2 When to Make This Application

If there is a need or desire to produce gas-cap gas either directly via a gas well or indirectly through oil zone perforations, application must be made to the ERCB.

CCP approval can take the form of one or more of the following:
- outright CCP that allows for production of gas-cap gas from both oil and gas wells
- CCP where gas may be produced through the oil zone perforations only
- CCP with a maximum gas withdrawal rate
- CCP with a maximum gas-oil ratio (GOR) above which the wells must be shut in
- CCP where only certain wells may be produced
- CCP for specific areas of a pool

2.4.3 Terms of Approval

A CCP application would likely be approved if the ERCB is satisfied that

1) gas-cap gas production would have a negligible impact on the ultimate oil recovery from the pool or that gas-cap gas production is unavoidable if oil is to be recovered from a given pool;

2) all gas production is or will be conserved; and

3) all potentially adversely affected parties in the pool agree with the proposed CCP scheme.

2.4.4 Requirements for an Application for Concurrent Production

Conservation

Requirements	Comments
1) Your geological interpretation of the pool involved, including	
a) oil and gas net pay isopach maps of the pool,	
b) where pool delineation or fluid interface locations are based on structural interpretation, a structure contour map of the pool and offsetting area,	

Requirements	Comments
c) an interpreted and annotated log cross-section or representative well log(s) showing the i) stratigraphic interpretation of the zone(s) of interest, ii) interpretation of the fluid interfaces present, iii) completions and treatments to the wellbore(s) with dates, iv) cumulative production, v) finished drilling date and kelly bushing (KB) elevation, and vi) the scale of the log readings, and	
d) a tabulation of your interpreted net pay, porosity, and water saturation for each well in the pool, along with the cutoffs, methodology, formulas, and constants used.	
2) If you are applying for CCP through certain wells, a list of the wells proposed for CCP.	
3) A statement of whether you have attempted recompletion efforts to reduce gas-cap gas production. If yes, state the results. If no, explain why not.	Gas cap production from oil wells may be reduced or eliminated by reperforating the well lower in the zone.
4) Your evaluation of the oil and gas reserves for the pool, including a) an estimate of the initial oil volume and gas volume in place, b) an estimate of the oil and gas recovery factors under the existing depletion mechanism and under the proposed CCP depletion strategy, c) a description of the methods used in determining (a) and (b) above (e.g.,	The stage of depletion of the pool may influence the ERCB's decision and should be discussed where appropriate.

Requirements	Comments
material balance, volumetric analysis, model study, a comparison of analog pools), and d) the supporting data used in determining (a) and (b) above and the sources of the data (e.g., pressure/volume/temperature [PVT] properties and source, pressure data and source).	
5) An estimate of the current oil in place and gas in place and an estimate of the annual oil and gas production under CCP.	An understanding of the current stage of depletion of the subject pool and the future rate of depletion of the gas cap(s) and the oil zone is key to evaluating the appropriateness of CCP for a pool.
6) An estimate of the gas cap segregation drive index, with supporting data and calculations.	Depending on its size relative to the associated oil pool, a gas cap can be a valuable source of pressure to the pool.
7) A discussion of whether you plan any operational changes for the subject pool (such as infill drilling) and, if so, what they are.	Potential changes to a pool, such as infill drilling, pool expansion, and changes in production operations, can alter a pool significantly, and hence a decision on CCP would be deemed premature.
8) Comments as to the feasibility of enhanced oil recovery and gas cycling if there is a retrograde condensate gas cap in the subject pool.	A request for CCP is premature if enhanced recovery or gas cap cycling are feasible but have not been implemented in the pool.
9) Confirmation that all gas will be conserved; if this is not the case, a detailed discussion on the feasibility of gas conservation.	Except in cases where gas production is unavoidable, gas production would not generally be approved in the absence of gas conservation. Your evaluation of gas conservation should use the decision tree and economic decision process set out in ERCB *Directive 060*, Sections 2.3 and 2.4. Under full gas conservation, only nonroutine flaring can occur. *Directive 060,* Section 2.6, defines nonroutine flaring at conserving facilities and specifies operational requirements to minimize this flaring.

Requirements	Comments
	Failure to address gas conservation in accordance with *Directive 060* may result in processing delays and deficiency requests.
10) An estimate of the ultimate oil and gas recovery from the subject pool under the status quo and under the proposed CCP.	Approval of CCP is contingent upon the gas production having little or no negative impact on ultimate oil recovery from the given pool.

Equity

Requirements	Comments
1) Documentation identifying notification to the unit operators, approval holders (if applicable), or well licensees in the ERCB-designated pool.	CCP applications often involve complex oil and gas equity issues. Failure to notify others involved in the pool will result in the return of your application.
2) Documentation confirming nonobjection from the above parties or specific details regarding objections or concerns.	

2.5 Application for Pool Delineation and Ultimate Reserves

2.5.1 Background

The ERCB establishes pool boundaries (vertically and horizontally) and assigns reserves to all oil and gas pools in Alberta. These are shown in Pool Orders (G Orders), annual reserve publications, and individual well and pool files. Well licensees of new oil wells outside of established G Orders must submit a completed application for a New Well Base Allowable or Base MRL (O-38 form).

The initial oil volume or gas volume in place for new pools is often based on simple building-block assignment areas and wellbore parameters. Initially, recovery factors for new pools may be based on analog pools in the area. Initial delineation reflects early geological and pressure information. As the pools are developed and further well data and performance data are available, delineation and reserves may be adjusted to reflect this new information. Net pay isopach maps, material balance analyses, decline analyses, and analytical and numerical models may take the place of the simple building-block approach. Different pressure trends or new gas/oil or oil/water interface information may alter pool boundaries.

The interpretation of pool reserves and delineation can affect regulatory requirements related to the operation and development of oil and gas pools in Alberta, as well as equity-related issues between operators.

2.5.2 When to Make This Application

Following the initial well assignment and if additional information becomes available that substantially changes current decisions, a well licensee may choose to, and in fact is encouraged to, make an application to change assigned reserves or vary pool delineation for several reasons, including

- **conservation** (For example, new evidence may permit a restricted gas well to produce if it is no longer within a gas cap or the second well in a DSU.)

- **equity** (For example, new evidence supports delineation for a well to a pool with a higher MRL or GPP.)

- **future applications** (For example, while reserves evaluations are required in many other applications in this directive, an applicant may choose to file a standalone reserve application. Maintaining a common reservoir information base or understanding differences may assist or accelerate processing future applications for matters addressed in this directive.)

- **provincial records** (For example, pool boundaries and reserves are the foundation for conservation and equity protection.)

The ERCB monitors pool performance and interprets new well information. As a result, the ERCB may also request well licensees to file reserve submissions to update reserves for pools of provincial significance.

2.5.3 How the ERCB Processes the Application

Upon receipt of a standalone pool delineation or reserve application, the ERCB analyzes the new evidence, reviews the applicant's interpretation, and assesses potential alternatives.

These applications are considered a technical information submission, and as such there are no specific requirements to notify and discuss the different interpretations with other well licensees.

The ERCB may seek input on the delineation or reserve interpretation from well licensees in the area as part of the overall review. The ERCB will consider all input prior to rendering a decision. This decision may not agree with the applicant, who may reapply as additional information becomes available.

2.5.4 Requirements for an Application for Pool Delineation

Requirements	Comments
1) The data and your interpretation, if the basis for proposing a pool delineation change is a specific, definitive piece of evidence.	There may be a sharp contrast in performance between wells, such as distinctly different pressure data, that conclusively supports delineation changes. Building-block reserves may be split or adjusted to reflect new boundaries.
2) A detailed reserve submission, if the basis for proposing a pool delineation change is a composite of indicators.	Analysis of a set of data provides for identification of both supporting and refuting elements and a "best fit" decision.

2.5.5 Requirements for an Application for Ultimate Reserves

Requirements	Comments
1) Your geological interpretation of the pool, including a) a net pay isopach map of the pool, including both oil and gas if there is an associated pool,	Your application must provide a geological interpretation of the entire pool, not just the portion underlying lands you own. If it will help to clarify your basis for pool delineation or other aspects of your geological interpretation, you should submit a log cross-section containing wells both within and outside of the pool. As a minimum you must submit at least one representative well log from a well in the pool showing the information required in 1(c).

Requirements	Comments
b) where pool delineation or fluid interface locations are based on structural interpretation, a structure contour map of the pool and offsetting area,	
c) an interpreted and annotated log cross-section or representative well log(s) showing the	Your application will have fewer processing delays if you provide a clear picture of your geological interpretation, including the potential for further pool development.
i) stratigraphic interpretation of the zone(s) of interest,	
ii) interpretation of the fluid interfaces present,	
iii) completions and treatments to the wellbore(s), with dates,	
iv) cumulative production,	
v) finished drilling date and kelly bushing (KB) elevation, and	
vi) scale of the log readings, and	
d) a tabulation of your interpreted net pay, porosity, and water saturation for each well in the pool, along with the cutoffs, methodology, formulas, and constants used.	
2) Your evaluation of the oil and gas reserves for the pool, including	If there are sufficient pressure, production, and PVT data, a material balance evaluation should be done and compared to the volumetric results.
a) an estimate of the initial oil volume and gas volume in place,	
b) an estimate of the oil and gas recovery factors,	Failure to provide the calculation methods and supporting data will delay processing of your application.
c) a description of the methods used in determining (a) and (b) above (e.g., material balance, volumetric analysis, model study, a comparison of analog pools), and	It is not necessary to provide production plots for the wells, except to illustrate a particular point or issue (e.g., decline analysis, specific well performance issues).
d) the supporting data used in determining (a) and (b) above and the sources of the data (e.g., pressure/volume/temperature [PVT] properties and source, pressure data and source).	

3. Production Control

Unit 3 Production Control

3.1 Commingled Production

3.1.1 Background

Historically, the standard practice for producing oil and/or gas in Alberta has been to maintain segregation between pools in the wellbore, unless otherwise approved by the ERCB, in accordance with Sections 3.050 and 3.060 of the *Oil and Gas Conservation Regulations (OGCR)*. Reasons for this control include

- avoiding wellbore and/or reservoir conditions that may adversely affect resource recovery,
- maintaining the ability to gather data on an individual-pool basis for resource evaluation and reservoir management,
- ensuring operational safety, and
- ensuring the protection of non-saline groundwater.

While these reasons for segregated production remain valid, commingling of production from multiple pools in the wellbore following approval by the ERCB is a longstanding practice in Alberta that has occurred over a wide range of formations and depths. The ERCB recognizes that commingling maximizes conservation in many cases and is necessary for economic and orderly development of lower productivity resources.

Recognizing the advantages of commingled production for situations where there is low risk associated with the commingling, the ERCB has implemented processes that allow commingling to occur subject to specific requirements being met. For higher risk situations, if the commingling of production from two or more pools in the wellbore is desired, an application for approval to commingle must be submitted to the ERCB in accordance with Section 3.1.8 of *Directive 065*.

3.1.2 Processes for the Management of Commingled Production

Three processes exist for the management of commingled production in the wellbore:

- development entity (DE),
- self-declared (SD) commingling, and
- approval of an application in accordance with *Directive 065*.

If the proposed commingling does not meet the requirements for commingling through the DE or SD process, the licensee must obtain approval for the commingling through the application process (Figure 3.1 in Section 3.1.4).

3.1.3 ERCB Expectations, Notification Requirements, and Compliance Assurance for All Commingled Production

3.1.3.1 Commingled Operations

The ERCB expects licensees to use good engineering practices when commingling production. This includes

- a good understanding of the reservoir and fluid properties prior to commingling;

- the collection of the appropriate reservoir data necessary to accurately assess and properly manage the reservoirs—this may exceed the minimum requirements prescribed by the ERCB; and
- review of all commingled wells and pools on an ongoing basis to ensure continued adherence to the requirements that originally supported the onset of commingled production.

Licensees must comply with the requirements set out in Sections 3.1.3.5, 3.1.5, 3.1.6, and 3.1.8 of this directive and submit any additional data collected for reservoir management in accordance with Section 11.005 of the *OGCR*.

The ERCB supports the water management objective of Alberta's *Water for Life: Alberta's Strategy for Sustainability* and stresses that a licensee must meet the requirements in *Directive 035: Baseline Water Well Testing Requirement for Coalbed Methane Wells Completed Above the Base of Groundwater Protection* and *Directive 044: Requirements for the Surveillance, Sampling, and Analysis of Water Production in Oil and Gas Wells Completed Above the Base of Groundwater Protection*.

3.1.3.2 Reporting and Administration of Commingled Production

The production from each well commingled in the wellbore in accordance with the DE or SD criteria must initially be reported through the Petroleum Registry of Alberta (Registry) using the DE or SD (commingled pool) code available on the Registry.

The ERCB will evaluate all wells in which production is initially reported with a DE or SD code. A commingled production code based on the geological evaluation of the pools completed in the well will then be assigned to the production by the ERCB to replace the DE or SD code for that well on the Registry. However, the creation of this new commingled pool code does not imply that other wells completed in the same pool(s) in the future may be commingled without further process. Each new well in which commingling is proposed through the DE or SD process must meet the DE or SD requirements, and production from the well must be reported to the Registry initially using the DE or SD code.

Commingled production resulting from approval of an application filed under Section 3.1.8 must be reported using the commingled pool code provided at the time of ERCB approval.

3.1.3.3 Data Collection

Data collection requirements associated with commingling under the various processes are set out in Sections 7.025, 11.005, 11.070, 11.102, and 11.140 of the *OGCR* and in *Directive 040*.

The data collection requirements for gas production from coals and shales are set out in Sections 11.005, 11.040, 11.070, 11.102, 11.140, and 11.145 of the *OGCR* and in *Directive 040*. Section 7.025 of the *OGCR* requires control wells for gas production from coals and shales. These control well requirements must be met by all licensees that have gas production from coals or shales.

Compliance with all data requirements will be enforced in accordance with *Directive 019: ERCB Compliance Assurance—Enforcement.*

3.1.3.4 Compliance Assurance

With the implementation of the new DE and SD processes, the ERCB has substantially strengthened its surveillance, audit, and enforcement processes to ensure that it is more effective in identifying and dealing with potential unauthorized commingling and other related noncompliant situations. Enforcement action for any noncompliance with commingled production requirements will be in accordance with *Directive 019*.
The ERCB believes that it is prudent for licensees to proactively review their wells to ensure that all production operations are in compliance with the regulations and *Directive 065*. Licensees should disclose any instances of unauthorized commingling in accordance with the requirements of Section 6 of *Directive 019*.

If there is commingling without approval, a licensee may qualify to use the DE or SD process described in this section to restore compliance in lieu of submitting a complete application.

In some compliance situations, pool designation may be an issue. The operator or licensee, as defined in the *Oil and Gas Conservation Act*, must comply with the current ERCB pool designation and is expected to make a technically sound assessment of pool interpretations.

Current ERCB pool designation information may be found on the official site for ERCB Field and Pool Orders at ERCB Home:Industry Zone:Industry Activity and Data: BOS - Board Order System. Field and pool orders are updated monthly.

Further information about pool designations can be obtained by contacting the ERCB by telephone at (403) 297-8311 (Customer Contact Centre) or by e-mail at PoolDesignation@ercb.ca.

If there are questions regarding pool interpretation in a compliance situation, the ERCB will notify the licensee directly in writing. The licensee will have an opportunity to respond to new evidence or rulings on complex or unclear situations in four ways. The licensee may

- qualify to use the DE or SD process described in this section to restore compliance,
- segregate pools in the well,
- submit a complete commingling application under *Directive 065* requirements to restore compliance, or
- submit a technically supported pool delineation application in accordance with *Directive 065*.

Failure to respond within the specified timeframe to an ERCB request regarding noncompliance or pool delineation issues results in enforcement action in accordance with *Directive 019*.

3.1.3.5 Notification Requirements for Commingling

A licensee or applicant must provide notification of commingling when using any of the three processes for the management of commingling: DE, SD, or application. The requirements for proper notification vary for each of the processes and must include well and interval details in accordance with the following requirements.

Sample notice letters for commingling are in Appendix B.

A) Notice of Commingling When Using the DE or SD Process Before Unsegregated Completion of the Well

If the lessors are not common for the different strata within the drilling spacing unit (DSU) where the wellbore proposed for commingling is located, the licensee must notify the Freehold mineral lessors of the proposed commingling a minimum of 15 working days prior to when it is anticipated the well would be completed to allow for commingled production. This notice must be provided regardless of whether the lessee ownership is common or pooled within the spacing unit. The notice must state that any concerns regarding the proposed completion are to be filed with the licensee. The licensee must make efforts to address the concerns raised to the satisfaction of the lessor(s) prior to completing the well.

If the licensee is unable to resolve the matters raised by the lessor(s), the production from the well may not be commingled using the DE or SD process. If commingling of production is desired in this situation, the licensee must make a full application in accordance with the Section 3.1.8. Any licensee making such an application will be required to address issues raised by the Freehold mineral lessor(s).

If the above-noted mixed lessor ownership situation does not exist, a licensee is not required to provide advance notice to any party that it is proposing to commingle production in the wellbore.

Refer to the Explanatory Notes in Section 3.1.7 for information on

- disputes regarding the proposed commingling,
- varying interests, and
- off-target wells.

B) Notice of Commingling When Using the DE or SD Processes After Unsegregated Completion of the Well

A licensee or applicant must provide notification of commingling when using any of the three processes for the management of commingling - DE, SD, or application. The requirements for proper notification varies for each of the processes and must include well and interval details in accordance with the following requirements.

A licensee that has commingled production using the DE or SD processes must provide notice of the commingling, at the minimum, to the licensees of all wells, other than abandoned wells, and to all Freehold mineral lessors in the standard DSU of the well in which commingling has occurred and the eight standard DSUs immediately offsetting the well in which commingling has occurred. In addition, the licensee must make a judgement as to whether parties outside specified areas may be directly and adversely affected and, if so, provide notification to those parties also.

Notice is to be provided within 30 days from the onset of commingling, unless prior notice was provided to the party in accordance with subsection (A) above.

Refer to the Explanatory Notes in Section 3.1.7 for information on

- disputes regarding commingling,
- varying interests, and
- off-target wells.

C) Notice of Commingling When Using the Application Process

The applicant must provide a minimum response period of 15 working days from the date the notification letter is mailed. The response period must be complete for all parties notified prior to the application for commingling being filed with the ERCB. Consent from notified parties is not required. However, the ERCB expects applicants to engage in meaningful discussions with any stakeholder that has raised concerns or questions. The ERCB expects that applicants will make reasonable efforts to resolve matters prior to filing an application.

The parties to be notified are different depending on the situation involved. Notification must be conducted as set out in Table 3.1. The applicant may be required to complete the notification requirements in more than one of the categories to address all the circumstances involved in the situation.

Table 3.1 Notification Requirements for Commingling Applications

If you are applying for commingling because	You must send notice of the proposed commingling at minimum to
1) the proposed commingling is for a situation where • there is actual or anticipated water production equal to or greater than 5 m^3/month in a well with perforations above the base of groundwater protection (BGWP), • there are unresolved equity issues with respect to the proposed commingling, • the production proposed for commingling includes gas from coals or shales outside a DE, or • there is a water well within a 600 m radius with a total depth less than 25 m from the top of the perforations of the well proposed for commingling.	• well licensees of nonabandoned wells in the standard[1] DSU where the subject well is located and in the eight standard DSUs offsetting the subject well, • Freehold lessors in the standard DSU where the subject well is located and in the eight standard DSUs offsetting the subject well, and • the owner(s) of water well(s) within the 600 m radius and 25 m depth.
2) the proposed commingling is for a situation where • the reservoir pressure of a pool or interval proposed for commingling exceeds 90 per cent of the lesser of the closure or breakdown fracture pressure of one of the other pools or intervals proposed for commingling, or • the well is in a designated oil sands area or is in a pool overlapping a designated oil sands area.	• well licensees of nonabandoned wells in the area of the smaller of the pools proposed for commingling and in the standard DSUs offsetting the smaller of the pools,[2] or if the smaller pool is a single-well pool, in the standard DSU where the subject well is located and in the eight standard DSUs offsetting the subject well, and • Freehold lessors in the area of the smaller of the pools proposed for commingling and in the standard DSUs offsetting the smaller of the pools, or if the smaller pool is a single-well pool, in the standard DSU where the subject well is located and in the eight standard DSUs offsetting the subject well.
3) the proposed commingling is for a situation where • the commingled stream contains H_2S, • the commingled stream contains oil, associated gas, and/or nonassociated gas, • there are two or more oil pools with production greater than 3 m^3/day from any well in any pool, • there is a pool(s) subject to an existing or proposed enhanced recovery scheme, or • commingling of production would address an operational issue not specifically detailed in this directive.	• well licensees of nonabandoned wells in the pools proposed for commingling,[3] and • Freehold lessors in the area of the smaller of the pools proposed for commingling and in the standard DSUs offsetting the smaller of the pools, or if the smaller pool is a single-well pool, in the standard DSU where the subject well is located and in the eight standard DSUs offsetting the subject well.
4) the proposed commingling is for an area.	• well licensees of nonabandoned wells in the area of application and in the standard DSUs offsetting the area of application, and • Freehold lessors in the area of application and in the standard DSUs offsetting the area of application.

[1] For a gas well, a standard DSU is one section; for an oil well, a standard DSU is one quarter section. If the proposed commingling mixes oil and gas, notice must be provided for the larger DSU involved.

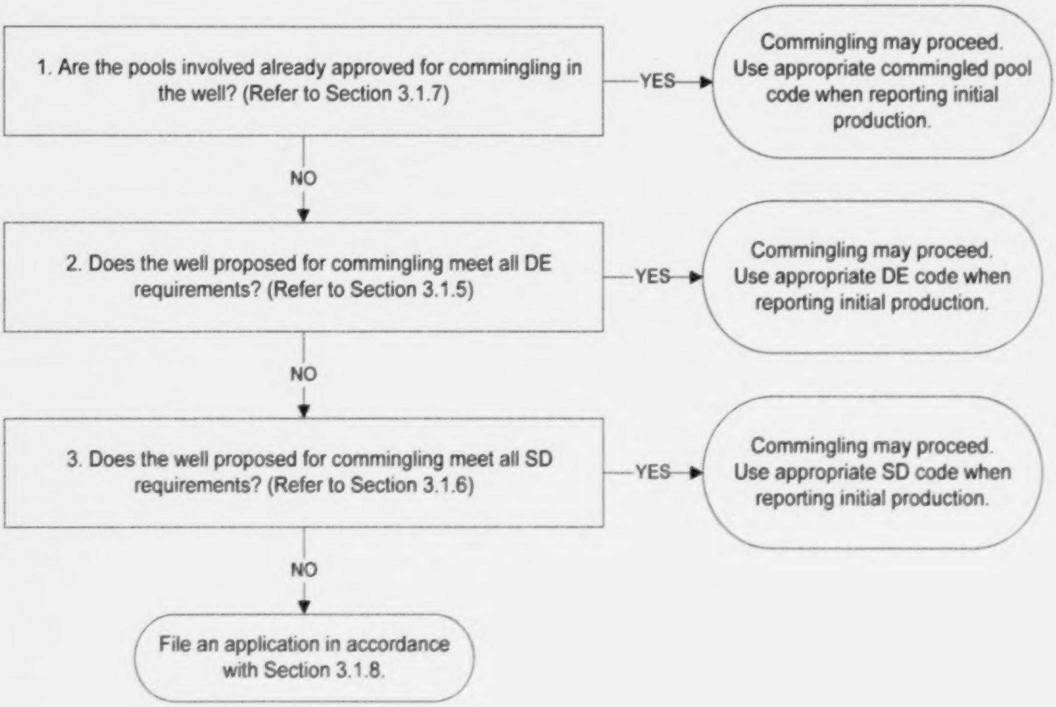
[2] Area of pool as defined by ERCB, or if the ERCB has not defined the pool when the notice is provided, the area of the pool as interpreted by the applicant. The ERCB may request the applicant to provide notice to additional parties if during the evaluation of the application the ERCB interprets the pool area to be larger than interpreted by the applicant.

[3] If a pool involved is extremely large, the applicant must make a judgement as to what area of the pool should be covered in the notification. This judgement would involve an assessment of which parties might be impacted by the proposed commingling. The ERCB may request the applicant to provide notice to additional parties if the ERCB considers that insufficient notice was provided.

3.1.4 Determination of Commingling Process to Use

A determination of which commingling process to use—DE, SD, or the application process—can be made using the decision tree in Figure 3.1.

Figure 3.1. Decision Tree to Determine Process to Commingle Production


1. Are the pools involved already approved for commingling in the well? (Refer to Section 3.1.7)
YES
Commingling may proceed. Use appropriate commingled pool code when reporting initial production.
NO
2. Does the well proposed for commingling meet all DE requirements? (Refer to Section 3.1.5)
YES
Commingling may proceed. Use appropriate DE code when reporting initial production.
NO
3. Does the well proposed for commingling meet all SD requirements? (Refer to Section 3.1.6)
YES
Commingling may proceed. Use appropriate SD code when reporting initial production.
NO
File an application in accordance with Section 3.1.8.

3.1.5 Unsegregated Gas Production Within a DE

A DE is an ERCB-defined entity consisting of multiple stacked formations in a specific area where there is an adequate understanding of the resources to allow commingled production of these formations to be the standard development practice. The ERCB has established DEs where commingled production of multiple pools over a large area is already occurring and there is minimal risk that unsegregated production will negatively affect conservation or the environment. A DE is administered as a single commingled pool by the ERCB, although individual formation-based contributing pools within the DE will be identified on the ERCB's Board Order System (BOS). ERCB Orders No. DE 2006-1 and DE 2006-2 show the geographic area and stratigraphic intervals for the two DEs that have been established. These orders are available on the ERCB Web site www.ercb.ca under Industry Zone : Rules Regulations Requirements : Management of Commingling.

If a licensee meets the requirements set out in Section 3.051(1) of the *OGCR* and in this unit, unsegregated gas production from a DE may commence at a well without an application being filed or an ERCB approval being issued. Each well commingled in a

DE must meet all DE requirements and report unsegregated production using the DE code.

Data requirements for wells with production commingled in the wellbore under the DE process include those set out in Sections 11.005, 11.070, 11.102, and 11.140 of the *OGCR* and in *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells—Minimum Requirements and Recommended Practices*.

The data collection requirements for gas production from coals and shales are set out in Sections 11.005, 11.040, 11.070, 11.102, 11.140, and 11.145 of the *OGCR* and in *Directive 040*. Section 7.025 of the *OGCR* requires control wells for the production of coalbed methane (CBM) and shale gas. These control well requirements must be met by all licensees that have gas production from coals or shales.

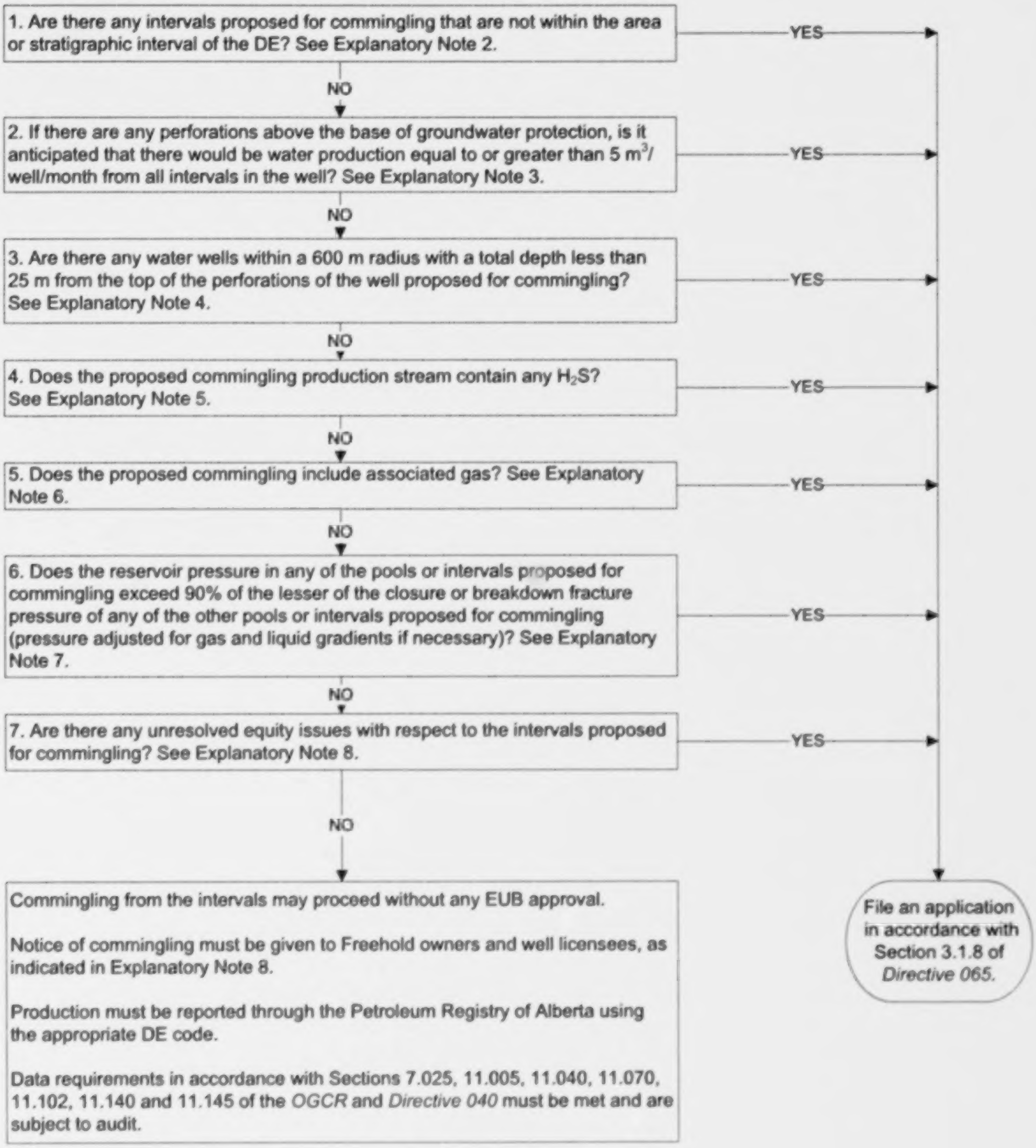
3.1.5.1 Requirements for Commingling of Gas Production in a DE

The following are the specific requirements set out in Section 3.051(1) of the *OGCR* that must be met before **nonassociated gas** production may be undertaken without segregation in the wellbore under the DE process:

1) There are no completions above or below the stratigraphic interval of the DE.
2) Anticipated or actual water production is less than 5.0 m^3/month if there are completions above the base of the BGWP.
3) The top of the completions is more than 25 m below the base of any water well within 600 m of the producing well.
4) There is no H_2S in the production stream.
5) The licensee has resolved any concerns of lessors or lessees of the mineral rights whose rights may be directly and adversely affected by the unsegregated production.
6) The reservoir pressure of any interval completed for production does not exceed 90 per cent of the fracture pressure of any other interval completed for production.
7) There is no production of gas associated with an oil accumulation.

Requirements respecting notification of commingling in accordance with the DE process are included in Section 3.1.3.5. For other additional information, refer to the decision tree in Figure 3.2 and the explanatory notes in Section 3.1.7.

Figure 3.2 Decision Tree for the Commingling of Gas Production from Intervals Within a Development Entity (DE)



1. Are there any intervals proposed for commingling that are not within the area or stratigraphic interval of the DE? See Explanatory Note 2.

2. If there are any perforations above the base of groundwater protection, is it anticipated that there would be water production equal to or greater than 5 m^3/well/month from all intervals in the well? See Explanatory Note 3.

3. Are there any water wells within a 600 m radius with a total depth less than 25 m from the top of the perforations of the well proposed for commingling? See Explanatory Note 4.

4. Does the proposed commingling production stream contain any H_2S? See Explanatory Note 5.

5. Does the proposed commingling include associated gas? See Explanatory Note 6.

6. Does the reservoir pressure in any of the pools or intervals proposed for commingling exceed 90% of the lesser of the closure or breakdown fracture pressure of any of the other pools or intervals proposed for commingling (pressure adjusted for gas and liquid gradients if necessary)? See Explanatory Note 7.

7. Are there any unresolved equity issues with respect to the intervals proposed for commingling? See Explanatory Note 8.

Commingling from the intervals may proceed without any EUB approval.

Notice of commingling must be given to Freehold owners and well licensees, as indicated in Explanatory Note 8.

Production must be reported through the Petroleum Registry of Alberta using the appropriate DE code.

Data requirements in accordance with Sections 7.025, 11.005, 11.040, 11.070, 11.102, 11.140 and 11.145 of the *OGCR* and *Directive 040* must be met and are subject to audit.

File an application in accordance with Section 3.1.8 of *Directive 065.*

3.1.6 SD Unsegregated Production

If a licensee meets the requirements set out in Sections 3.051(2) and (3) of the *OGCR* and in this unit, unsegregated gas production may commence using the SD process without an application being filed or an ERCB approval being issued. Each well commingled using this process must meet all SD requirements and report unsegregated production using the SD code.

The SD process is for commingling of production from gas pools only or oil pools only. Commingled production from gas and oil pools in the same wellbore is not permitted under this process and requires a commingling application. The SD commingling process has limited applicability with respect to oil production at present, being available for use with only very low-rate oil wells. Also, the SD process may not be used if the proposed commingling involves any H_2S, gas production from coal or shale, or wells in a designated oil sands area or in a pool that overlaps into a designated oil sands area.

Production from a well completed within a DE may be commingled with production from intervals above or below the stratigraphic intervals of the DE using the SD process, provided that all requirements for SD commingling are met.

Data collection requirements associated with commingling under the SD process are set out in Sections 11.005, 11.070, 11.102, and 11.140 of the *OGCR* and in *Directive 040*. The SD commingling process is the same for all situations, but well testing requirements vary for gas wells depending on the well flow rate, as set out in *Directive 040*.

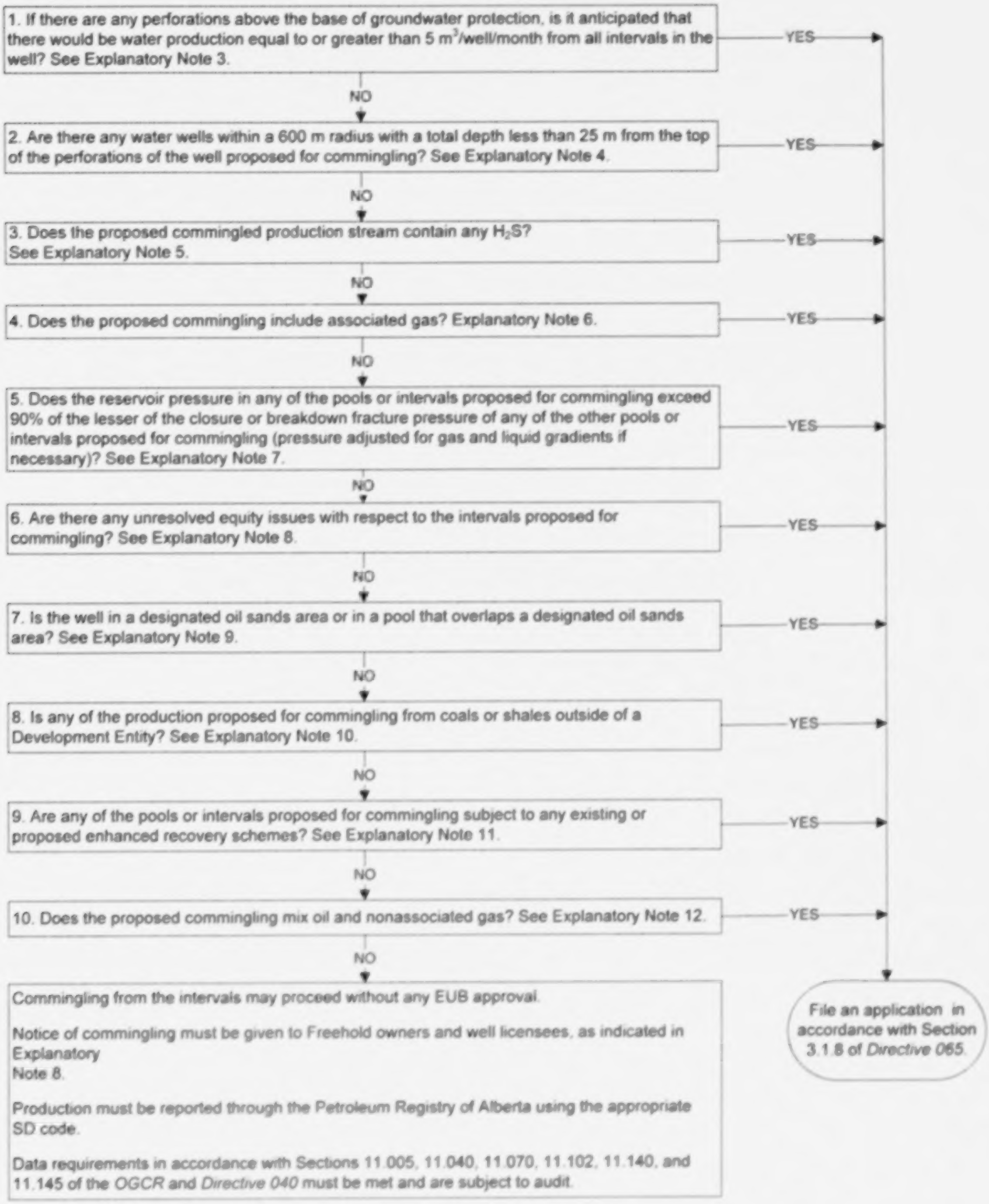
3.1.6.1 Requirements for SD Commingling of Gas Production

The following are the specific requirements set out in Section 3.051(2) of the *OGCR* that must be met before **nonassociated gas** production may be undertaken without segregation in the wellbore under the SD process:

1) Anticipated or actual water production is less than 5.0 m^3/month if there are completions above the base of the groundwater protection.
2) The top of the completions is more than 25 m below the base of any water well within 600 m of the producing well.
3) There is no H_2S in the production stream.
4) The licensee has resolved any concerns of lessors or lessees of the mineral rights whose rights may be directly and adversely affected by the unsegregated production.
5) The reservoir pressure of any interval completed for production does not exceed 90 per cent of the fracture pressure of any other interval completed for production.
6) There is no production of gas associated with an oil accumulation.
7) The well is not in a designated oil sands area or in a pool that overlaps a designated oil sands area.
8) There is no production of gas from coal or shale outside a DE.
9) The pools or intervals are not subject to any existing or proposed enhanced recovery scheme.

For additional information, refer to the decision tree in Figure 3.3 and the explanatory notes in Section 3.1.7.

Figure 3.3. Decision Tree to Determine If the Proposed Commingling Is a Candidate for Self-Declared Gas Commingling in a Well



1. If there are any perforations above the base of groundwater protection, is it anticipated that there would be water production equal to or greater than 5 m^3/well/month from all intervals in the well? See Explanatory Note 3.

2. Are there any water wells within a 600 m radius with a total depth less than 25 m from the top of the perforations of the well proposed for commingling? See Explanatory Note 4.

3. Does the proposed commingled production stream contain any H_2S? See Explanatory Note 5.

4. Does the proposed commingling include associated gas? Explanatory Note 6.

5. Does the reservoir pressure in any of the pools or intervals proposed for commingling exceed 90% of the lesser of the closure or breakdown fracture pressure of any of the other pools or intervals proposed for commingling (pressure adjusted for gas and liquid gradients if necessary)? See Explanatory Note 7.

6. Are there any unresolved equity issues with respect to the intervals proposed for commingling? See Explanatory Note 8.

7. Is the well in a designated oil sands area or in a pool that overlaps a designated oil sands area? See Explanatory Note 9.

8. Is any of the production proposed for commingling from coals or shales outside of a Development Entity? See Explanatory Note 10.

9. Are any of the pools or intervals proposed for commingling subject to any existing or proposed enhanced recovery schemes? See Explanatory Note 11.

10. Does the proposed commingling mix oil and nonassociated gas? See Explanatory Note 12.

Commingling from the intervals may proceed without any EUB approval.

Notice of commingling must be given to Freehold owners and well licensees, as indicated in Explanatory Note 8.

Production must be reported through the Petroleum Registry of Alberta using the appropriate SD code.

Data requirements in accordance with Sections 11.005, 11.040, 11.070, 11.102, 11.140, and 11.145 of the *OGCR* and *Directive 040* must be met and are subject to audit.

File an application in accordance with Section 3.1.8 of *Directive 065*.

3.1.6.2 Requirements for SD Commingling of Oil Production

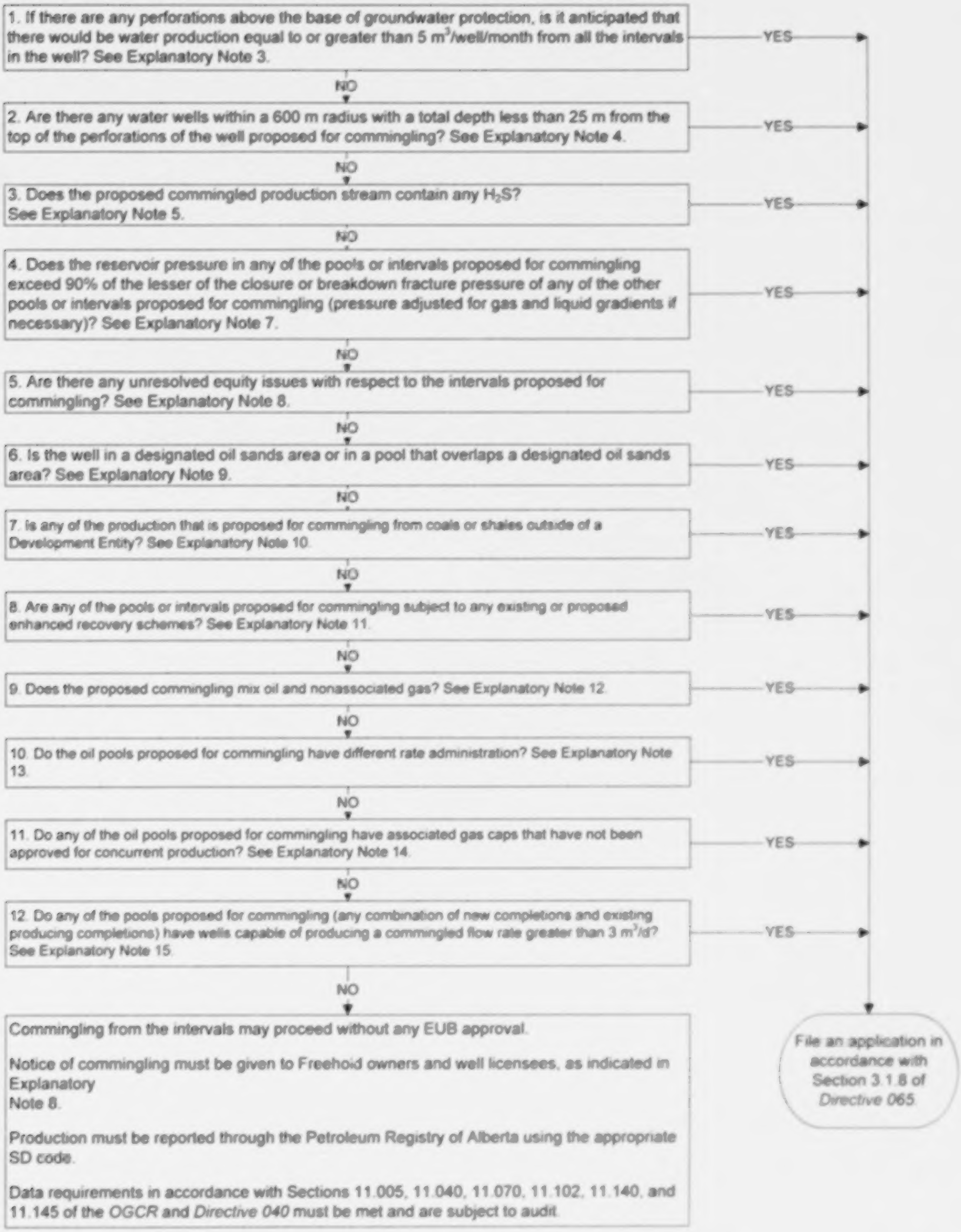
The SD commingling process has limited applicability with respect to oil production at present, being available for use with only low rate oil wells. Also, while the commingling of oil production under the SD process is on a well-by-well basis, as it is for all SD commingling, the production rate of all other oil wells in the pools involved with the SD commingling must be taken into consideration, as noted in requirement 12 below, prior to proceeding with using the SD process for the commingling of oil production. This measure is in effect to ensure that resource conservation issues associated with higher productivity oil pools are considered through an application in accordance with Section 3.1.7 prior to commingling commencing in the pools.

A licensee must meet the following requirements set out in Section 3.051(3) of the *OGCR* before **oil** production may be undertaken without segregation in the wellbore under the SD process:

1) Anticipated or actual water production is less than 5.0 m^3/month if there are completions above the BGWP.
2) The top of the completions is more than 25 m below the base of any water well within 600 m of the producing well.
3) There is no H_2S in the production stream.
4) The licensee has resolved any concerns of lessors or lessees of the mineral rights whose rights may be directly and adversely affected by the unsegregated production.
5) The reservoir pressure of any interval completed for production does not exceed 90 per cent of the fracture pressure of any other interval completed for production.
6) The well is not in a designated oil sands area or in a pool that overlaps a designated oil sands area.
7) There is no production of gas from coal or shale outside a DE.
8) The pools or intervals are not subject to any existing or proposed enhanced recovery scheme.
9) There is no production of gas that is not associated with an oil accumulation.
10) The oil pools have the same rate administration.
11) There are no oil pools that have associated gas caps that have not been approved for concurrent production.
12) The unsegregated flow rate of every well in the pools proposed for commingling is less than 3 m^3/day when calculated over 3 consecutive months of production. (This means that the average operating day flow rate of the commingled well for the last 3 calendar months of production—total production for last 3 months with production / total hours on production during those 3 months x 24 hours/day—immediately preceding the well being commingled under the SD process is less than 3.0 m^3/operating day, and the flow rate of every well in the pools involved with the SD commingling of the well is also less than 3.0 m^3/operating day when calculated in the same manner.)

For additional information, refer to the decision tree in Figure 3.4 and the explanatory notes in Section 3.1.7.

Figure 3.4. Decision Tree to Determine If the Proposed Commingling Is a Candidate for Self-Declared Oil Commingling in a Well



1. If there are any perforations above the base of groundwater protection, is it anticipated that there would be water production equal to or greater than 5 m^3/well/month from all the intervals in the well? See Explanatory Note 3.

2. Are there any water wells within a 600 m radius with a total depth less than 25 m from the top of the perforations of the well proposed for commingling? See Explanatory Note 4.

3. Does the proposed commingled production stream contain any H_2S? See Explanatory Note 5.

4. Does the reservoir pressure in any of the pools or intervals proposed for commingling exceed 90% of the lesser of the closure or breakdown fracture pressure of any of the other pools or intervals proposed for commingling (pressure adjusted for gas and liquid gradients if necessary)? See Explanatory Note 7.

5. Are there any unresolved equity issues with respect to the intervals proposed for commingling? See Explanatory Note 8.

6. Is the well in a designated oil sands area or in a pool that overlaps a designated oil sands area? See Explanatory Note 9.

7. Is any of the production that is proposed for commingling from coals or shales outside of a Development Entity? See Explanatory Note 10.

8. Are any of the pools or intervals proposed for commingling subject to any existing or proposed enhanced recovery schemes? See Explanatory Note 11.

9. Does the proposed commingling mix oil and nonassociated gas? See Explanatory Note 12.

10. Do the oil pools proposed for commingling have different rate administration? See Explanatory Note 13.

11. Do any of the oil pools proposed for commingling have associated gas caps that have not been approved for concurrent production? See Explanatory Note 14.

12. Do any of the pools proposed for commingling (any combination of new completions and existing producing completions) have wells capable of producing a commingled flow rate greater than 3 m^3/d? See Explanatory Note 15.

Commingling from the intervals may proceed without any EUB approval.

Notice of commingling must be given to Freehold owners and well licensees, as indicated in Explanatory Note 8.

Production must be reported through the Petroleum Registry of Alberta using the appropriate SD code.

Data requirements in accordance with Sections 11.005, 11.040, 11.070, 11.102, 11.140, and 11.145 of the *OGCR* and *Directive 040* must be met and are subject to audit.

File an application in accordance with Section 3.1.8 of *Directive 065*.

3.1.7 Explanatory Notes to Determine If the DE or SD Processes May Be Utilized

1. Are the pools involved already approved for commingling in the well?

To answer this question, the list of pools approved for commingling, as identified in the field-based MU orders, must be checked. An evaluation needs to be made as to whether each productive interval in the well proposed for commingling is currently part of an existing pool as defined by the ERCB. If each interval proposed for commingling is within the boundaries of existing pools as defined at the time the licensee is conducting its evaluation and these pools are already approved for commingling, production from the pools may be commingled in the subject well without any notice to the ERCB. Commingled production must be reported to the Registry using the existing commingled production code for the pools involved.

If at the time of the evaluation, the pools in the well have not been approved for commingling as set out in the field-based MU orders, the licensee may proceed to use the DE or SD decision tree to determine whether the well is a candidate for commingling through the DE or SD process. If the well is a candidate for commingling using the DE or SD process, production may be commingled in the wellbore immediately. Commingled production must be reported to the Registry using the DE or SD code available for each field, and the licensee must operate within the DE and SD criteria at all times. If the proposed commingling does not meet the criteria for either DE or SD commingling and commingling is desired, an application in accordance with Section 3.1.8 of *Directive 065* must be submitted.

2. Are there any intervals proposed for commingling that are not within the area or stratigraphic interval of the DE?

To answer this question, the licensee must confirm if the well and intervals proposed for commingling are within the area and stratigraphic interval of the related DE. This information is provided on the order for each DE, which is available on the ERCB Web site www.ercb.ca under Industry Zone : Rules Regulations Requirements : Management of Commingling in the Wellbore. If the well is outside the area of the DE or there are any perforated intervals within the wellbore that are outside the stratigraphic interval of the DE, the well is not permitted to commingle production under the DE process. If commingling of production is desired in this circumstance, the licensee may proceed to the SD decision tree and determine if the proposed commingling meets the criteria for SD commingling. If the proposed commingling does not meet the criteria for either DE or SD commingling and commingling is desired, an application in accordance with Section 3.1.8 of *Directive 065* must be submitted.

3. If there are any perforations above the BGWP, is it anticipated that there would be water production equal to or greater than 5 m3/well/month from all intervals in the well?

A licensee may determine whether any interval proposed for commingling is above BGWP from the data provided in ERCB *ST55: Alberta's Base of Groundwater Protection (BGWP) Information*.

The volume of 5 m^3/well/month is proposed as a practical cutoff to allow for small volumes of water, including water of condensation that may periodically need to be cleaned out of the well.

If it is anticipated that water volumes equal to or greater than 5 m^3/well/month could be produced from any or all intervals in the well that has perforations above the BGWP, a licensee may not commingle production using the DE or SD process.

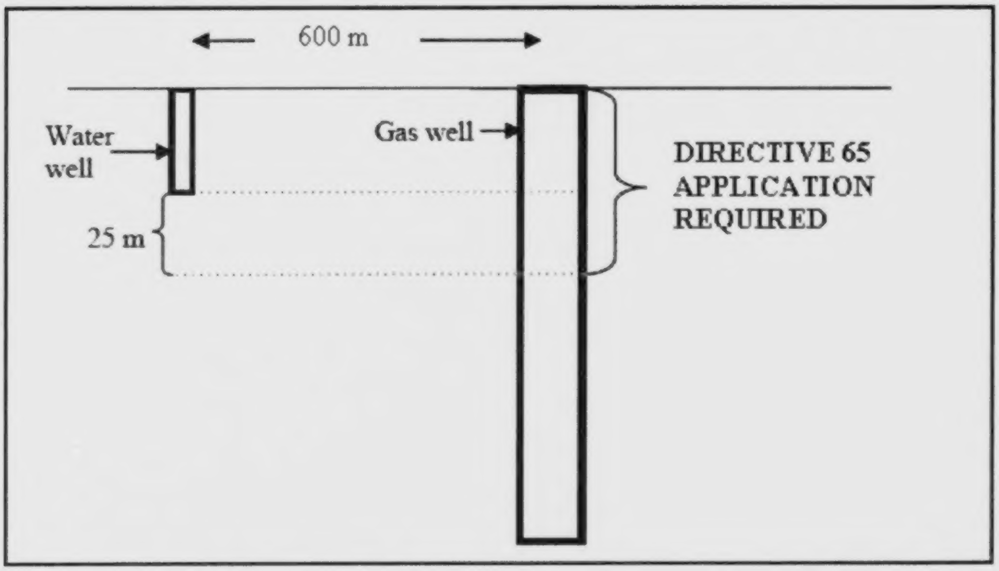
If an existing well that is to be recompleted for commingled production has produced greater than 5 m^3/well/month of water from the well in any of the last 12 months, a licensee may not commingle production using the DE or SD process.

If the licensee wishes to commingle production in this circumstance, an application in accordance with Section 3.1.8 of *Directive 065* must be submitted. The application must provide a case that water produced with commingled production will not contaminate groundwater or adversely impact the recovery of gas from coals. Licensees should note that commingling of production in wells with completions above the BGWP that have actual or anticipated water production equal to or greater than 5 m^3/month conflicts with *Directive 044*.

Licensees must also ensure that operations comply with the AENV *Water Act*, taking particular note that non-saline water may not be produced without a groundwater diversion permit, non-saline aquifers may not be mixed, and saline and non-saline aquifers may not be mixed.

4. Are there any water wells within a 600 m radius with a total depth less than 25 m from the top of the perforations of the well proposed for commingling?

This requirement has consideration for *Directive 027: Shallow Fracturing Operations—Interim Controls, Restricted Operations, and Technical Review* and for AENV's *Standard for Baseline Water—Well Testing for Coalbed Methane/Natural Gas in Coal Operations, April 2006*. If the situation as illustrated below exists, the licensee may not commingle production using the DE or SD process. If the licensee wishes to commingle production in this circumstance, an application in accordance with Section 3.1.8 of *Directive 065* must be submitted.



5. Does the proposed commingled production stream contain any H_2S?

Gas or oil with any H_2S content greater than 0.00 mole/kilomole is considered to contain H_2S. This is consistent with Table 7.1 in *Directive 056: Energy Development Applications and Schedules*.

A licensee may not commingle gas or oil production containing H_2S using the DE or SD process. If commingling of production is desired in this situation, an application in accordance with Section 3.1.8 of *Directive 065* must be submitted.

6. Does the proposed commingling include associated gas?

Commingling of associated gas and nonassociated gas may not occur using the DE or SD (gas) process. If the licensee wishes to commingle any nonassociated gas with associated gas, an application in accordance with Section 3.1.8 of *Directive 065* must be submitted.

7. Does the reservoir pressure in any of the pools or intervals proposed for commingling exceed 90 per cent of the lesser of the closure or breakdown fracture pressure of any of the other pools or intervals proposed for commingling (pressure adjusted for gas and liquid gradients if necessary)?

Closure pressure is the pressure needed to open and/or extend a fracture resulting from previous stimulation operations. Breakdown pressure is the pressure needed to initially fracture a reservoir during stimulation operations.

Having extreme pressure differences between pools proposed for commingling raises a safety issue in that wellbore control may be jeopardized if fluid from a high-pressured reservoir flows into a lower-pressured reservoir that has a well completion or wellhead equipment not designed for such high pressures. Another concern about the commingling of production from pools with extreme pressure differences arises when a new well is drilled into a pool that has an unusually high pressure due to cross-flow from a commingled completion; this raises a safety issue in that the party drilling nearby may not anticipate the higher pressure.

The onus is on the licensee to evaluate this issue. If the reservoir pressure in any of the pools proposed for commingling exceeds 90 per cent of the lesser of the closure or breakdown fracture pressure in any other pools proposed for commingling (with pressure adjusted for gas and liquid gradients in the wellbore if necessary), a licensee may not commingle gas in the wellbore without the specific approval of the ERCB through an application filed in accordance with Section 3.1.8 of *Directive 065*. Any application requesting approval for commingling in this situation must show that the pools involved will be isolated during any shut-in periods and that casing and cement integrity and wellhead design are adequate for the proposed completion.

8. Are there any unresolved equity issues with respect to the intervals proposed for commingling?

a) Notice

Notice of Commingling Using the DE or SD Process Before Completing the Well in an Unsegregated Manner

If the lessors are not common for the different strata within the wellbore where commingling is proposed, the licensee must notify the Freehold mineral lessors of the proposed commingling a minimum of 15 working days prior to when it is anticipated the well would be completed for commingled production. This notice must be provided regardless of whether the lessee ownership is common or pooled within the spacing unit. The notice should provide that any concerns regarding the proposed completion are to be filed with the licensee. The licensee must make efforts to address the concerns raised to the satisfaction of the lessor(s) prior to completing the well. If the licensee is unable to resolve the matters raised by the lessor(s), the production from the well may not be commingled using the DE or SD process. If commingling of production is desired in this situation, an application in accordance with Section 3.1.8 of *Directive 065* must be submitted. Any licensee making such an application will be required to address issues raised by the Freehold mineral lessor(s).

If the above-noted lessor ownership situation does not exist, a licensee is not required to provide advance notice to any party that it is proposing to commingle production in the wellbore.

Notice of Commingling Using the DE or SD Process After Completing the Well

A licensee that has commingled production using the DE or SD process must provide notice of the commingling, at the minimum, to the licensees of all wells, other than abandoned wells, and to all Freehold mineral lessors in the section to be commingled and the eight DSUs immediately offsetting the well in which commingling has occurred. In addition, the licensee must make a judgement as to whether parties outside specified areas could be potentially directly and adversely affected and, if so, provide notification to those parties also.

Notice is to be provided within 30 days from the onset of commingling.

Disputes Regarding Commingling Under the DE or SD Process

If any dispute arises with an offsetting licensee as to whether the commingling should have occurred, the parties should attempt to resolve the issue through negotiation, appropriate dispute resolution, and other mutually acceptable means. If the dispute is not resolved, either party may contact the ERCB for resolution. After review of the matter, the ERCB may require that production in the well under dispute be segregated.

Although it would normally be expected that any concerns raised in response to notice of commingling would be brought forward by Freehold mineral lessors or licensees with an interest within the area of notice, concerns raised by parties outside of that area must also be addressed. If the ERCB were asked to make a decision in such a case, it would consider the arguments brought forward on their own merits and would not automatically reject the concerns raised solely because the objecting party's interests are located outside of the notice area.

b) Varying Interests

Potential DE or SD well candidates that have varying ownership or royalty interests in the DSU must not commence commingled production unless all parties involved in the DSU have agreed. Licensees should be aware that well spacing may not be the same for all zones.

c) Off-target Wells

Commingling of production in the wellbore may also be an issue if a well is off target, because commingling will affect the licensee's ability to obtain segregated pool data, which in turn may adversely affect the ability of offsetting licensees to determine the possible effects of the off-target well. For example, the offsetting licensee may not be able to adequately judge whether the off-target well is in the same pool as the offsetting licensee's well because of a lack of segregated pool data.

If a licensee is considering drilling an off-target well and is also considering commingling production in the wellbore from the onset, it is recommended that the licensee determine in advance whether such commingling is likely to be an issue with any offsetting mineral holder with a wellbore, so that the question on equity on the decision trees can be adequately answered.

If there is commingling in an off-target well and subsequently a dispute arises respecting the off-target well, the ERCB may require the licensee to segregate production from the pools in question so that data can be obtained to resolve the dispute.

Sample notice letters for commingling using the DE are SD processes are included in Appendix B.

9. Is the well in a designated oil sands area or in a pool that overlaps a designated oil sands area?

The licensee must check ERCB Orders No. OSA 1, OSA 2, and OSA 3 showing designated oil sands areas and strata. These orders are available on the ERCB Web site ***www.ercb.ca*** and from ERCB Information Services. Because the issue of gas production in oil sands areas can be complex and the optimum processes for dealing with the production of gas reservoirs in contact with bitumen reserves have not been determined, wells in this area are not candidates for SD commingling. If approval to commingle gas production in a designated oil sands area or from any pool that overlaps a designated oil sands area is desired, an application in accordance with Section 3.1.8 of *Directive 065* must be submitted.

10. Is any of the production proposed for commingling from coals or shales outside a DE?

Production from coals and shales is not well understood; therefore SD commingling may not occur in wells located outside a DE. If approval to commingle production in this situation is desired, an application in accordance with Section 3.1.8 of *Directive 065* must be submitted and validated control wells are required, as outlined in the Control Well Requirements on the ERCB Web site www.ercb.ca.

11. Are any of the pools or intervals proposed for commingling subject to any existing or proposed enhanced recovery scheme?

Conservation may be jeopardized if any pool proposed for commingling is part of an enhanced recovery scheme. The lack of segregation could result in operational difficulties and the loss of data required to properly manage the scheme. In this situation, SD commingling may not occur. If approval to commingle production is desired, an application in accordance with Section 3.1.8 of *Directive 065* must be submitted.
12. Does the proposed commingling mix oil and nonassociated gas?

Conservation of oil may be jeopardized if there is commingling of oil and nonassociated gas. The lack of segregation could make it difficult to determine if the oil pool is a candidate for enhanced recovery. In this situation, SD commingling may not occur. If approval to commingle is desired, an application in accordance with Section 3.1.8 of *Directive 065* must be submitted.

13. Do the oil pools proposed for commingling have the same rate administration?

Oil pools proposed for commingling must have a common rate administration. This means that all pools have been approved for good production practice (GPP) or, alternatively, that all wells in the pools are subject to a maximum rate limitation (MRL). The MRLs can be different for the wells.

If commingling is desired for pools with different rate administration, the well licensee's first step must be to file an application requesting the same rate administration for all pools involved (i.e., all pools are either approved for GPP or all pools are subject to MRL). If the ERCB approves the application to establish the same rate administration, the well licensee may then review the well(s) and pools involved to determine if commingling may occur under the SD process. If the well(s) and pools still do not meet all the SD criteria and approval to commingle in this situation is still desired, an application in accordance with Section 3.1.8 of *Directive 065* must be submitted.

14. Do any of the oil pools proposed for commingling have associated gas caps that have not been approved for concurrent production?

If commingling is desired for any pool with a gas cap that has not been previously approved by the ERCB for concurrent production, the well licensee's first step must be to file an application requesting approval of the appropriate concurrent production. If the ERCB approves the application for concurrent production, the well licensee may then review the well(s) and pools involved to determine if commingling may occur under the SD process. If the well(s) and pools still do not meet all the SD criteria and approval to commingle in this situation is still desired, an application in accordance with Section 3.1.8 of *Directive 065* must be submitted.

15. Do any of the [oil] pools proposed for commingling (any combination of new completions and existing producing completions) have wells capable of producing a commingled flow rate greater than 3 m^3/d?

Pools that have wells capable of producing a commingled flow greater than 3 m^3/d are considered to be potential enhanced recovery candidates.

For each existing segregated producing oil pool, the rate must be determined while the well is producing in a pumped-off fashion. The rate must be an average of the last three months of production, calculated using operating hours; the three months need not be consecutive, nor is there a minimum time for production in a given month.

For a new oil pool/well, the anticipated production rate must be determined from test data collected from the oil zones in the well.

If approval to commingle in this situation is desired, an application in accordance with Section 3.1.8 of *Directive 065* must be submitted.

3.1.8 Approval to Commingle Production Through an Application

If the proposed commingling does not meet the criteria to allow commingling through the DE or SD processes and is not already approved for the pools in question, the licensee must obtain approval for commingling through the application process. The licensee must file an application in accordance with Sections 3.050 and 15.220 of the *OGCR* and Section 3.1.8 of *Directive 065*. The applications may request commingling on a well, pool, or area basis.

For wells, pools, or areas applied for under this process, the intervals applied for commingling must remain segregated until the ERCB has issued an order approving the application.

In summary, the application process may be used to obtain approval to commingle production in accordance with Section 3.050 of the *OGCR* if the proposed commingling is not permitted through the DE or SD process. In addition, applications may be made for area-based commingling; however, area-based applications should only be submitted for areas and strata that do not qualify for the DE or SD process.

3.1.8.1 How to Make a Commingling Application

Applications must be filed electronically using the Electronic Application Submission (EAS) process, accessed through the Digital Data Submission (DDS) screen on the ERCB Web site www.ercb.ca. The ERCB will review all applications to ensure that the requirements for commingling applications have been met. Incomplete applications or those containing significant errors will be closed.

3.1.8.2 How the ERCB Processes the Application

The ERCB reviews all commingling applications to ensure that oil and/or gas recovery will be optimized, there will not be any adverse affects from the commingling, safety is maintained, and non-saline groundwater is protected.

The ERCB will disposition applications electronically, with the disposition being available for viewing through IAR Query for 30 days after the disposition of the application. IAR Query is accessible via the Applications page on the ERCB Website.

3.1.8.3 Requirements for an Application for Commingled Production on a Well, Pool, or Area Basis

The requirements for all situations where commingling may be desired are numbered and described later in this section. The information required for any specific commingling application will depend on the reasons that the application is being made. Table 3.2 shows the numbered requirements that must be met in each of the situations noted. Depending on the situation, the applicant may be required to choose more than one of the categories and meet the combined requirements in the application.

If the proposed commingling includes gas from coal or shale, an applicant must file an application for approval of commingling on an area basis, rather than for a well or pool-based approval. An area-based approval can include one or more DSUs. Applications should be formatted so that the number of the requirement in Table 3.2 corresponds with the numbered discussion in the application.

Table 3.2 Summary of Requirements for Commingling on a Well, Pool, or Area Basis

Reason for Filing a Commingling Application	Requirements for Application
1. There is actual or anticipated water production equal to or greater than 5 m^3/month in a well with perforations above the BGWP.	1, 2(a), 2(b)(i), 3-6, 9, 12-16
2. There is a water well within a 600 m radius with a total depth less than 25 m from the top of the perforations of the well proposed for commingling.	1, 2(a), 2(b)(i), 2b(ii), 3, 4, 7-9, 12-16
3. There is H_2S in the proposed commingled production stream.	1, 2(a), 2(b)(iii), 3, 4, 9-16
4. The proposed commingling is for • nonassociated and associated gas, • oil and nonassociated gas, • oil, associated gas, and nonassociated gas, or • oil pools (any combination of new completions and existing producing completions) having wells capable of producing a commingled flow rate more than 3 m^3/d.	1, 2(a), 2(b)(iv), 3, 4, 12-16, 19
5. The reservoir pressure of a pool or interval proposed for commingling exceeds 90 per cent of the lesser of the closure or breakdown fracture pressure of one of the other pools or intervals proposed for commingling.	1, 2(a), 2(b)(v), 3, 4, 12-15, 17
6. There are unresolved equity issues with respect to the proposed commingling.	1, 2(a), 2(b)(vii), 3
7. The well is in a designated oil sands area or is in a pool overlapping a designated oil sands area.	1, 2(a), 3, 4, 12-16, 20
8. A pool proposed for commingling is subject to an existing or proposed enhanced recovery scheme.	1, 2(a), 2(b)(vi), 3, 4, 12-16, 18
9. Area-based commingling is desired, including for gas production from coals and shales outside a DE.	1, 2(a), 2(b)(vii), 3, 4, 9, 12-16, 21
10. Commingling of production would involve an operational issue not specifically detailed in *Directive 065.*	All requirements are to be cited in the application. For any requirement not applicable to the situation, the applicant must indicate that the requirement does not apply.

An application for approval to commingle production must include the information for those items as specified in the table above and as described below.

Requirements	Comments
1) A statement of what is being requested, including a) a reference that the application is being made under Section 3.050 of the *OGCR*, and b) if approval for commingling is requested on a well or pool basis, the name of the well(s) and pools that are the subject of the application, together with identification of each productive interval (kelly bushing [KB] elevation, in metres) in each well of interest from which you propose to commingle production, or c) if an area-based commingling approval is being requested, a list of the sections in the area of application and the zones to which the commingling would apply, together with a geophysical log of a type well with annotations identifying the subject zones.	If the pools involved have not been defined by the ERCB at the time of application, the pools should be referred to as undefined. Inclusion of the intervals ensures that there is no confusion about the pools involved, which might occur if the ERCB and an applicant have different terminology for the same zones.
2) A discussion of the reasons why you are requesting commingling, including, as appropriate, a) a statement of the DE or SD criteria that were not met or the operational issues that would be addressed by commingling, and b) justification as to why commingling should be granted, including, where required, (i) why commingling will not contaminate any non-saline water interval, with supporting technical evaluation as appropriate, (ii) why commingling will not cause any issues in the water well(s), with supporting technical evaluation, including • the geological setting of the shallowest perforated zone and water-bearing zone(s), • the details of the fracture stimulation proposed or done, and	In general, improved economics with commingling alone or the ability to conduct fewer tests under a commingling approval are not considered valid reasons for an application. Your discussion of why commingling should be permitted should draw on the information and evaluations included elsewhere in the application.

Requirements	Comments
- an evaluation of the potential of fracture propagation from the hydrocarbon zone into the water zone, (iii) why commingling of the sour gas will not cause problems, including contamination of sweet pool, with supporting technical evaluation, (iv) why commingling will not adversely impact recovery from the oil pool, with supporting technical evaluation, (v) why the differences in pressure between the pools will not be a safety issue if commingling is permitted, with supporting technical evaluation; provide an explanation of why the higher pressured zone/s cannot be produced first so that the pressure depletion will allow the addition of lower pressured zones at a later date, (vi) why the commingling will not adversely impact the operation of the enhanced recovery scheme, with supporting technical evaluation, or (vii) why the commingling will not have any adverse impacts, with supporting technical evaluation.	
3) A description of your notice program, including a) lists of the parties notified,	The parties that must be notified are set out in the Table 3.1 in Section 3.1.3.5. You must provide a tabulation of Freehold owners and well licensees notified. The tabulation should include the legal land description by DSU for the area of notification and the names of the mineral owner(s), except as noted below, and well licensees contacted for each DSU. The tabulation must not include the names of individual Freehold mineral owners, as this might raise privacy issues. For these persons, the tabulation should specify "Freehold – Individual." You must compile a list of the names, legal description of the land involved, and mailing

Requirements	Comments
	addresses of all Freehold mineral owners notified and have this information available to the ERCB on request. As this list contains personal information, it is **not** to be filed upon submitting the application to the ERCB.
b) evidence of notification, and	Provide a written statement that all of the Freehold mineral owners and well licensees as required by Table 3.1 have been notified. Provide an example of the notification letter sent to individual Freehold mineral owners and to well licensees. Do not include any individual's name or contact information in the example of the letter sent to Freehold mineral owners. Do **not** provide copies of any notification letters that were sent unless specifically requested by the ERCB.
c) summary of notification results.	Provide a statement of the results of your notification program. The ERCB does not require letters of consent from the parties notified. Do **not** file copies of any consent letters that may have been received unless requested to do so by the ERCB. You must include the details of unresolved concerns, both written and verbal, in the application filed with the ERCB. Include a discussion of how you have addressed the unresolved concerns and the outcome you expect from the ERCB regarding the unresolved concerns. If an unresolved objection is from an individual Freehold mineral owner, do not include the person's name, contact information, or written correspondence. In these cases the objector must be identified as "Freehold – Individual" in the application. You must have the name, contact information, and written correspondence from such individuals available to the ERCB on request. If a substantiated, valid objection is filed that cannot be resolved by the parties involved in a reasonable time, the ERCB will typically schedule a public hearing to consider the application.

Requirements	Comments
4) If there are perforations above 600 m KB, identification of the base of groundwater protection (BGWP) (m KB).	The BGWP may be obtained from the data provided in ERCB *ST55-2007: Alberta's Base of Groundwater Protection (BGWP) Information* or from your own analysis. If you have completed your own analysis, you must include the geological and/or technical information to support your pick of the BGWP in the application.
5) a) Identification of the source (intervals), composition, and volumes of the water, and	You must conduct sampling and analysis of the water in accordance with *Directive 044*.
b) a discussion of how anticipated water production was estimated or how produced water was measured or estimated.	Well licensees are responsible for ensuring that the volume of water produced from a well is measured accurately.
6) If the applicant is proposing to produce non-saline water, the number of the water diversion permit that has been obtained from Alberta Environment.	The *Water Act* prohibits the production on non-saline water unless such production is approved by a water diversion permit obtained from Alberta Environment.
7) A figure showing the water-bearing interval(s) in relation to all perforations within 25 m of the water-bearing interval or the shallowest productive perforated interval.	You must evaluate whether there are water wells within the 600 m radius and 25 m depth for all wells in the pools proposed for commingling, even if the application itself is for a single well, as the ERCB will consider approving commingling on a pool rather than well basis only in exceptional circumstances as required by Section 3.050 of the *OGCR*.
8) A copy of the results of a water well test analysis if conducted; if not conducted, an explanation of why a test was not conducted.	If you offered to test the water well but the owner of the water well rejected the offer, a statement should be made in the application to this effect.
9) A copy of the fluid analysis for each pool and coal and shale zone proposed for commingling.	
10) Confirmation that the infrastructure to produce and transport the reservoir fluid is appropriate for the commingled production stream.	

Requirements	Comments
11) Confirmation that an ERCB-approved emergency response plan (ERP) incorporating the proposed commingling is in place or, alternatively, a discussion addressing the status of the ERP.	If the proposed commingling will result in an increase in the potential H_2S release volume, the ERCB must ensure that there is an up-to-date ERP in place prior to its decision on the application. If no up-to-date ERCB-approved ERP is in place but is required, the applicant must confirm that an application for the updated ERP has been filed directly with the ERCB Operations Group for review. See *Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry* for further details on emergency response planning. If you consider that an updated ERP is not required, your discussion must indicate why you believe that is the case.
12) A discussion of the geology of the pools involved in the application.	Knowledge of the geological setting for a pool can add insight as to the quality of the pool (for example, a reservoir matrix that would result in poor permeability and/or poor productivity) and the likelihood that the pool may be extensive (e.g., the depositional environment, the trapping mechanism).
13) For all types of reservoirs excluding coal or shale reservoirs, your interpretation of each pool involved in the application, including a) a net pay isopach map of the pool, including both oil and gas if there is an associated pool, b) if pool delineation or fluid interfaces are based on structural interpretation, a structure contour map of the pool and offsetting area, and	You do not have to include net pay isopach maps if the pools are considered to be single well; however, you should explain why the pools are considered to be single-well pools and whether this is based on offset well control and/or engineering data. If the size of the pool is unknown due to poor well control, the ERCB may consider it premature to approve commingling, unless there are compelling reasons to do so. If pools are larger, not in a stage of advanced depletion, and/or have good deliverability, the ERCB may consider that segregated production should be maintained to allow for the collection of segregated pool data for the purpose of enhancing pool management to obtain optimum recovery of reserves. You should only include a structural map if it is a key in determining fluid interfaces or pool delineation.

Requirements	Comments
c) a tabulation of the interpreted net pay, porosity, and water saturation for each well in the pool, and cutoffs applied.	If you do not supply tabulated well data for all wells in the pools, you must explain why.
14) For all types of reservoirs including coal and shale reservoirs, an interpreted and annotated log cross-section or representative well log(s) showing a) stratigraphic interpretation of the zone(s) of interest, b) interpretation of the fluid interfaces present, c) completions and treatments to the wellbore(s), with dates, d) cumulative production, e) finished drilling date and KB elevation, and f) the scale of the log readings.	For cases involving gas pools, an annotated representative well log is sufficient. If oil pools are involved and the potential for enhanced oil recovery must be addressed, you should include the annotated cross-section.
15) A tabulation of a) the results of deliverability, flow, or production tests on **each** pool proposed for commingling in the wells of interest, together with an indication of the type of test involved (e.g., AOFP) and the date of the test, and b) if a well is currently producing, a tabulation summarizing the current productivity of each pool in the subject well.	The ERCB is not prepared to consider requests to approve commingling of production from pools unless those pools are considered to be capable of production. This would at minimum entail flow test data showing that the individual pool is capable of production. (Copies of the actual tests are not required for the application unless specifically requested.) If a well is producing, only a summary of current productivity for each pool in the well involved is required. You should not include the entire production history of the well in the application, unless the production trend is the basis for the request. If the productivity of a pool has declined significantly or is low from the outset, the case for commingled production is strengthened in that it can be argued that commingling would allow each pool involved to produce economically for a longer time and thus enhance overall recovery.
16) Initial and current sandface pressure information in accordance with *Directive 040* for **each** pool, together with an indication of the type and date of the test or the analysis used to estimate the	The ERCB is not prepared to consider requests to approve commingling of production from pools unless there is pressure information for each pool.

Requirements	Comments
pressures, and if there are pressure differences between pools, evaluations of a) the potential for cross-flow of reservoir fluids between the pools, particularly when the well is shut in, and b) why the pressure differences will not result in any adverse impacts if commingling is permitted.	Pressure differences between pools raises the possibility that commingling of production may result in the cross-flow of reservoir fluids between pools. The cross-flow may contaminate a non-saline water zone or result in an adverse impact on the recovery of hydrocarbons from one or both pools involved. For example, recovery may be adversely impacted by cross-flow of fluids by gas entrapment behind perforations, by precipitate formation resulting from incompatible reservoir fluids, or by the movement of fine particles. In addition, a water-sensitive formation may be damaged by the cross-flow of water.
17) If the application has been filed because the reservoir pressure of a pool or interval proposed for commingling exceeds 90 per cent of the lesser of the closure or breakdown fracture pressure of one of the other pools proposed for commingling, a) calculations to demonstrate that the reservoir pressure of a pool or interval proposed for commingling exceeds either • 90 per cent of the fracture closure pressure of a shallower zone that has been fracture stimulated, or • 90 per cent of the fracture breakdown pressure of a shallower zone that has not been fracture stimulated, b) confirmation that the shallow pool will be segregated during periods that the well is shut in, including a wellbore schematic showing the actual or proposed completion to ensure segregation, and c) pressure decline analysis to demonstrate the length of production time needed for the pressure of the higher-pressured pool to decline so that segregation is not required during periods the well is shut in.	Closure pressure is the pressure needed to open and/or extend a fracture resulting from previous stimulation operations. Breakdown pressure is the pressure needed to initially fracture a reservoir during stimulation operations. Having extreme pressure differences between pools proposed for commingling raises a safety issue in that wellbore control may be jeopardized if fluid from a high-pressured reservoir flows into a lower-pressured reservoir that has a well completion or wellhead equipment not designed for such high pressures. Another concern about the commingling of production from pools with extreme pressure differences arises when a new well is drilled into a pool that has an unusually high pressure due to cross-flow from a commingled completion; this raises a safety issue in that the party drilling nearby may not anticipate the higher pressure.
18) Identification of the existing or proposed enhanced recovery scheme.	This must include the approval number of any existing scheme or the application number or details of a proposed scheme.
19) For any oil pools involved,	

Requirements	Comments
a) confirmation that the oil pools have a common rate control or, alternatively, a separate application requesting a change in rate control has been submitted to the ERCB,	Production from oil pools with different rate controls may not be commingled.
b) if there is associated gas, confirmation that approval of concurrent production has been obtained or that a separate application requesting concurrent production approval has been submitted to the ERCB,	Separate applications must be submitted for commingling approval and for concurrent production and good production practice.
c) a discussion respecting whether the oil pool involved contains or has potential for an enhanced oil recovery scheme and, if so, the possible effect of approval for commingling of production on the effectiveness of such a scheme, and	Commingling of production in the wellbore might not be an optimum strategy when it may hamper the effectiveness of an enhanced recovery scheme.
d) an evaluation of the oil and gas reserves for each pool, including i) an estimate of the initial oil volume and gas volume in place, ii) an estimate of the oil and gas recovery factors, iii) a description of the methods used in determining (i) and (ii) above (e.g., material balance, volumetric analysis, model study, a comparison of analog pools), and iv) the supporting data used in determining (i) and (ii) above and the sources of the data (e.g., pressure/volume/temperature [PVT] properties and source, pressure data and source).	
20) For any gas pool located in an oil sands area, a) confirmation that there is no shut-in order for the subject well and zones arising from a gas/bitumen proceeding and that the wells and zones are not subject to any upcoming gas/bitumen proceeding, b) a statement that the well involved would be producing in accordance with ERCB *Interim Directive (ID) 99-1*, and c) a discussion indicating that the loss of individual pool data resulting from the commingling will not adversely affect future evaluation of the impact of gas production on the bitumen resource in	For wells drilled and/or completed in a defined oil sands strata after July 1, 1998, you must submit an application and obtain approval from the ERCB before any gas, other than solution gas, may be produced. In an area where pool performance and pressure data are scarce (e.g., low drilling density, limited production), the ongoing collection of zonal data may prove crucial to future decisions on gas production and to the re-evaluation of past gas production approvals. Unless the ERCB is satisfied that the region of influence of the gas zones in the area is well defined, commingling may be denied.

Requirements	Comments
the area.	
21) If an area-based approval is being requested,	
a) evidence that the application applies to specific zones in all portions of the contiguous area for which the rationale for commingling of production from the identified zones exists (not just to the applicant's working interest lands),	
b) a discussion demonstrating that conservation goals are at least as likely to be achieved through commingling of production as through segregated operations,	The discussion should show that the loss of individual pool data resulting from the commingling will not adversely affect the ability of the operator to adequately mange pool operations in future.
c) a tabulation of all relevant data for the zone and area of interest (not just the applicant's working interest lands), including i) deliverability and flow test information, together with the type and date of the test, ii) initial and current zone/pool pressures, together with an indication of the type and date of the test, and iii) a summary of the current daily production rate (as calculated on operating time) for the wells and pools in the area under evaluation, together with a discussion showing that there are sufficient existing data to demonstrate a pattern of production performance in the area for which the application is being made, and	The density of well information required to successfully make a case that there are sufficient existing data to demonstrate a pattern of production performance in the area involved will vary according to the complexity of the geology in the area.
d) for the commingling of gas from coals and/or shales outside a DE, confirmation that a submission requesting the ERCB to validate the required pressure/flow and desorption control wells for the coal or shale production has been filed or, alternatively, if all necessary control wells have already been validated, a list of the locations of the validated control wells.	

3.2 Background to Good Production Practice, Gas-Oil Ratio Penalty Relief, and Special Maximum Rate Limitation

Most new oil pools in Alberta initially have rate controls applied. These restrictions are designed to ensure that oil pools in the province are not significantly depleted before the pool's optimum depletion strategy can be determined. This helps to ensure that enhanced oil recovery (EOR) feasibility is addressed early in the pool's life, along with solution-gas conservation, concurrent production, and any equity problems among operators in the pool. The tool used by the ERCB to impose rate controls is the Maximum Rate Limitation (MRL) Order.

Generally, the ERCB will not approve accelerated production rates to improve the economics for initiating enhanced recovery or data gathering to determine and assist in optimization studies. The ERCB also notes that the applicant should refer to *Directive 007-1: Allowables Handbook* for details on the administration of allowables and *Interim Directive (ID) 99-2: Revised Policy on Administration of Oil MRL's and Overproduction* regarding retirement of overproduction rules.

Applications to remove oil rate controls fall into three categories:

- a request that the oil pool be removed from the MRL system (good production practice [GPP])
- a request that an amendment to the MRL Order modify or remove gas-oil ratio (GOR) penalties
- a request that an amendment to the MRL Order increase the MRL above its reserves-based value (Special MRL)

Before approving any of the above applications, the ERCB must be satisfied that

- the pool is operating under its optimum depletion strategy to ensure that economic oil recovery is maximized,
- gas conservation has been addressed using the decision tree and economic decision process set out in ERCB *Directive 060,* and
- equity issues have been resolved.

Because the issues are the same in each application, the ERCB often approves GPP when GOR penalty relief and/or Special MRL have been applied for. The following section outlines the content requirements for these three applications, starting with GPP. GOR penalty relief and Special MRL are treated as alternatives to GPP when unique circumstances exist that would preclude granting GPP.

3.3 Application for Good Production Practice—Primary Depletion Pools

This section deals only with GPP applications for pools under primary depletion. GPP removes a pool from restrictions imposed by the ERCB's monthly MRL Order and is granted under Section 10.060 of the *Oil and Gas Conservation Regulations*. Under GPP, the wells in a pool are not restricted by base allowable or GOR penalties. However, as the name implies, operators are expected to produce the wells in accordance with good engineering practices to optimize oil recovery. The ERCB may rescind GPP approval if new information or technology indicates that production under GPP may affect conservation or the rights of other owners in the pool. GPP may be granted with concurrent production restrictions on gas cap production or other conditions.

Note that for pools under primary depletion, GPP is granted to the pool, not to individual wells. For pools where EOR schemes exist, GPP is usually granted only to the ER oil scheme areas.

3.3.1 Requirements for an Application for GPP

Requirements	Comments
1) Your geological interpretation of the pool, including	
a) a net pay isopach map of the pool, including both oil and gas if there is an associated pool,	For primary pools, GPP is granted to the entire oil pool. Therefore, the application must provide a geological interpretation of the entire pool, not just lands you own.
b) where pool delineation or fluid interface locations are based on structural interpretation, a structure contour map of the pool and offsetting area,	If it will help to clarify your basis for pool delineation or other aspects of your geological interpretation, you should submit a log cross-section containing wells both within and outside of the pool. As a minimum, you must submit at least one representative well log from a well in the pool showing the information required in item 1(c).
c) an interpreted and annotated log cross-section or representative well log(s) showing the	
i) stratigraphic interpretation of the zone(s) of interest,	You must provide a clear picture of your geological interpretation, including the potential for further pool development.
ii) interpretation of the fluid interfaces present,	
iii) completions and treatments to the wellbore(s), with dates,	
iv) cumulative production,	
v) finished drilling date and kelly bushing (KB) elevation, and	
vi) scale of the log readings, and	

Requirements	Comments
d) a tabulation of your interpreted net pay, porosity, and water saturation for each well in the pool, along with the cutoffs, methodology, formulas, and constants used.	
2) Your evaluation of the oil and gas reserves for the pool, including a) an estimate of the initial oil volume and gas volume in place, b) an estimate of the oil and gas recovery factors, c) a description of the methods used in determining (a) and (b) above (e.g., material balance, volumetric analysis, model study, and a comparison of analog pools), and d) the supporting data used in determining (a) and (b) above and the sources of the data (e.g., pressure/volume/temperature [PVT] properties and source, pressure data and source).	The size of oil and gas cap reserves affects depletion strategy, EOR feasibility, and gas conservation economics. The stage of depletion of the pool may influence the ERCB's decision and should be discussed where appropriate. If there are sufficient pressure, production, and PVT data, you should do a material balance evaluation and compare it to the volumetric results. Failure to provide information on the calculation methods and supporting data will delay processing of your application. It is not necessary to provide production plots for the wells, except to illustrate a particular point or issue (e.g., decline analysis, specific well performance issues).
3) A discussion and analysis of why waterflooding or some other form of enhanced oil recovery (EOR) is not feasible for this pool. This should include a) your screening criteria and supporting calculations and data, b) if EOR was found to be technically feasible but uneconomic, your economic evaluation and supporting data, and c) if numerical simulation was used, a description of the model, the input data, results of history matching, cutoffs used for each case, descriptions of the cases run, and summaries and analyses of the results.	EOR evaluation is a critical part of any GPP application, and processing delays will result if it is not done properly. If the ERCB agrees that the pool is a single-well oil pool with no potential for expansion or further drilling or is in good communication with a fully active aquifer system, EOR will not be an issue. If EOR is considered feasible, GPP will be denied pending implementation of EOR.

Requirements	**Comments**
4) Analysis, discussion, and supporting data to show that producing the pool under GPP is the optimum depletion strategy for the pool. If there is gas-cap gas production, you need to supplement this with the information required for a CCP application and identify further conditions needed to approve CCP (e.g., gas rate limit, maximum GOR).	This should build on the analyses in items 3 and 4 above. Having eliminated EOR, you must satisfy the ERCB that producing wells at unrestricted rates will not reduce primary recovery. If the MRL and GOR penalties do not restrict production in the pool now or in the future, you should include this in your discussion. At this point you may wish to request a reduced pressure test frequency in the pool if you can show that a lesser frequency is appropriate. Failure to adequately address CCP will delay processing. Please refer to the CCP application requirement in Unit 2, Section 2.4.
5) A discussion of the status of gas conservation from wells in the pool, including wells owned or operated by others. This discussion should a) confirm that full gas conservation from all wells is occurring and will continue, or b) outline the schedule for implementation of full gas conservation, or c) justify why you are not proposing full gas conservation under GPP.	Your evaluation of gas conservation should use the decision tree and economic decision process set out in ERCB *Directive 060*, Sections 2.3 and 2.4. Under full gas conservation, only nonroutine flaring can occur. *Directive 060*, Section 2.6, defines nonroutine flaring at conserving facilities and specifies operational requirements to minimize this flaring. Failure to address gas conservation in accordance with *Directive 060* will result in processing delays and deficiency requests.
6) Individual legible maps showing a) the lessees in and adjoining the applied-for pool, and b) the lessors in and adjoining the applied-for pool.	To ensure clarity, you should construct your own map, rather than submit a photocopy from part of a commercial land map you purchased. Confusion about ownership in the area will delay processing.
7) If there is mixed ownership in the pool, a) state that you are applying on behalf of all well licensees in the pool, or	You are encouraged to apply on behalf of all well licensees in the pool. If not, the ERCB's application process must ensure that parties having a bona fide interest in the application are provided an opportunity to intervene. For

Requirements	Comments
	more information, refer to the *Energy Resources Conservation Act* and the corresponding *Alberta Energy and Utilities Board Rules of Practice*.
b) identify the well licensees not represented, explain why they are not represented, and evaluate the impact that GPP approval will have on the rights of these owners.	Your evaluation of the impact on parties not represented should include supporting data; otherwise processing will be delayed.

3.4 Application for Gas-Oil Ratio Penalty Relief

GOR penalties are applied to an oil well's MRL when the producing GOR exceeds the base GOR. The penalty factor is calculated by taking the ratio of the base GOR to the producing GOR. The MRL is then multiplied by this penalty factor to determine the adjusted MRL (the permitted production rate). GOR penalty relief is applied for under Section 10.060 of the *Oil and Gas Conservation Regulations*.

GOR penalty relief applications face the same issues as GPP. For this reason, when processing a GOR penalty relief application, the ERCB will often grant GPP, with full gas conservation as a condition. GOR penalty relief is approved through the application of a net GOR penalty factor, which reduces the GOR penalty by subtracting out any fuel gas or gas delivered to an approved gas gathering system.

GOR penalty relief is not automatic when gas is conserved. When GORs rise significantly above the solution GOR of the oil, this indicates that pressure depletion and/or gas cap coning is occurring, neither of which is desirable for optimum oil recovery. These issues must be addressed before an application can be approved, despite ongoing gas conservation.

3.4.1 Using the O-33 Form

To apply for GOR penalty relief, operators often use the O-33 form, which was introduced in 1989 as part of *Informational Letter (IL) 89-14*. The O-33 form is specifically targeted at small (one or two wells), low-quality pools (rates below minimum allowable initial high-water cuts). *Directive 065* supersedes the requirements set out in *IL 89-14*, but the ERCB will continue to accept the O-33 form for small, low-quality oil pools if the conservation and equity issues are not complex. See Appendix C for a copy of the O-33 form.

3.4.2 Requirements for an Application for GOR Penalty Relief

For GOR penalty relief application requirements, please use the GPP application requirements and comments (Section 3.3.1). Note that CCP must also be applied for (see Section 2.4) if the high GORs are a result of production from a gas cap. You should also state in your application why you are applying for GOR penalty relief rather than GPP.

3.5 Application for Special Maximum Rate Limitation (MRL)

A Special MRL is an MRL approved by the ERCB that is greater than the reserves-based MRL. Special MRLs can be applied to entire pools or individual wells. Relatively few Special MRL applications are received or approved each year because, like GOR penalty relief, Special MRL applications have the same issues involved as GPP. For this reason, when processing a Special MRL application, the ERCB will often grant GPP. A Special MRL is applied for under Section 10.060 of the *Oil and Gas Conservation Regulations*.

3.5.1 Requirements for an Application for a Special MRL

For Special MRL application requirements, please use the GPP application requirements and comments (Section 3.3.1). You should also state in your application why you are applying for Special MRL rather than GPP.

3.6 Application to Amend or Rescind a Gas Allowable Order

3.6.1 Background

There are essentially three situations when the ERCB may issue a gas allowable (GA) order for the purpose of setting the maximum allowed gas production rate for a gas well or wells in a pool:

- if the ultimate recovery of gas may be adversely affected by unrestricted production rates (Section 10.300(1) of the *Oil and Gas Conservation Regulations* [*OGCR*]),
- if a gas well is completed outside of its prescribed target area and it is necessary to apply an off-target penalty to the well's base allowable for equity reasons (Section 4.070(1) of the *OGCR*, ERCB *Interim Directives (ID) 94-2* and *94-5*), and
- if the Board has approved a fractional section as a drilling spacing unit and there is a need to apply an area-ratio production penalty or off-target penalty for equity reasons (Section 4.050(1) and (2) of the *OGCR*).

Section 10.095 of the *OGCR* designates that the base allowable for a gas well shall be its maximum daily allowable (Q_{max}). The calculation of Q_{max} is explained in Section 10.300(1)(c) of the *OGCR* and in ERCB *Informational Letter (IL) 85-10*. In all instances above, the penalties are applied against the well's Q_{max} and an annual allowable (based on this Q_{max} and the number of days in the year) is assigned.

3.6.2 When to Make This Application

When a well is subject to an ERCB gas allowable (GA) order and the well's licensee believes that circumstances warrant the allowable being rescinded or amended, an application can be made to change the allowable in accordance with Section 10.300(4) of the *OGCR*. There are a number of reasons for a change to a gas well's allowable, including

- equity (e.g., there is no longer an offsetting productive well),
- conservation (e.g., there is no longer a reason to restrict the rate for conservation reasons),
- pool delineation (e.g., data support a new pool interpretation that does not warrant the application of a gas allowable to the well), or
- administrative (e.g., the well can no longer meet the allowable).

The original reason for the initial assignment of the allowable will dictate the basis for any requested change, and the application must address what has changed since the original allowable was assigned to the well to justify the application. The majority of gas allowables are assigned for equity purposes, resulting in equity matters being of primary consideration in most applications to amend or rescind a GA order.

3.6.3 How the ERCB Processes the Application

Upon receipt, the ERCB reviews the application for completeness according to the following requirements. Particular attention is paid to equity considerations. If pool delineation is an issue (i.e., the ERCB's current pool delineation is different from the applicant's and this difference is material to the assignment of the allowable), the ERCB will undertake geologic and engineering reviews of the pool delineation. In all cases, contact with offset licensees will be checked to ensure that proper notification is conducted. In particular, contact with any offset licensee that caused the assignment of the original allowable will be ensured. Once the technical, administrative, and equity aspects of the application have been reviewed, a decision will be issued or a hearing will be set to consider the matter. Generally, a hearing is called only if there are bona fide objections to a change in the allowable from an offset licensee or if the ERCB does not agree that a change is warranted and the applicant wishes the matter be considered at a hearing.

3.6.4 Requirements for an Application to Amend or Rescind a Gas Allowable Order

An application under Section 10.300(4) of the *OGCR* to either amend or rescind the maximum daily allowable prescribed to a gas well must include the following. The information required can vary, as noted in the Comments column below, depending on the reason for the original allowable being assigned.

Administration

Requirements	Comments
1) A statement that the application is made in accordance with Section 10.300(4) of the *OGCR*.	This is a legal requirement.
2) The unique well identifier of the well for which you are requesting a change in the allowable.	
3) A summary of the basis of the application.	Why do you believe that the maximum daily allowable should be changed? You may need to address conservation and/or equity, depending on the reason for the original assessment of the allowable to the well.

Conservation

Requirements	Comments
1) A map showing the net pay isopachs and zero edge of the pool.	The ERCB requires this information to confirm the pool extent. The pool's net pay and zero edge must reflect your actual geological interpretation of the pool.
2) A map showing the status of each well completed in the pool.	
3) A map showing the structure of the top and base of porosity and the initial and present fluid interfaces.	This information is required only when the allowable was originally assigned for conservation reasons, and then only when structure is pertinent to the application.
4) A map showing isobars of the pool.	This is generally only required if pool delineation is an issue.
5) Tabulations of a) reservoir parameters, b) the estimated initial in-place volumes of gas and other hydrocarbons in the pool, c) for the pool, the current rate of production of gas, other hydrocarbons, and water and an estimate of the probable pool production rates under the proposed operating conditions, and d) for each well, the current productive capacity, the current average production rate, and the production rate anticipated under the proposed operating conditions.	The information referred to in 5(c) and (d) is generally required for the entire pool only when allowables have been set for an entire pool for conservation reasons or when pool delineation is an issue. When only a portion of the pool is affected by the subject allowable, data on just the subject well and immediately offsetting wells are usually sufficient.
6) Discussions of a) pertinent characteristics or conditions that exist within the pool, including geological factors, reservoir characteristic, general or local fluid interface movements, pressure gradients, areal drainage, or production conditions,	Information referred to in 6(a) and (b) is required only when the allowable was originally assigned for conservation reasons.

Requirements	Comments
b) the predicted future recovery of gas and other hydrocarbons from the pool under existing production rate limitations and under the proposed operating conditions, particularly the uniformity of drainage within the pool, and c) the conservation and administrative benefits that would accrue from granting the application.	
7) An interpreted and annotated log cross-section or representative well log(s) showing a) stratigraphic interpretation of the zone(s) of interest, b) interpretation of the fluid interfaces present (current and original, if applicable), c) completions and treatments to the wellbore(s), with dates, d) cumulative production, e) finished drilling date and kelly bushing (KB) elevation, f) the scale of the log readings, and	This information is required only when the allowable was originally assigned for conservation reasons or when pool delineation is an issue. You may present this cross-section in a number of ways (as one representative well log, several well logs, or a detailed cross-section of the entire pool) depending on the complexity and heterogeneity of the pool.
g) a tabulation of your interpreted net pay, porosity, and water saturation for each well in the pool, along with the cutoffs, methodology, formulas, and constants used.	If you do not supply tabulated well data for all wells in the pool, you must explain why the data are not included (e.g., the allowable affects only a portion of the entire pool). As a minimum, you must provide the data for the subject well and all immediately offsetting wells.
8) A discussion of	
a) well completion and recompletion details and assessment of the prospects for control of water production in the future,	The information for 8(a) to (e) is required only when the allowable originally was assigned for conservation reasons.
b) operating problems,	

Requirements	Comments
c) the effect of increased production on liquid coning, terminal fluid interface position, and interpool interference,	
d) the effect on the rates of production of any oil, condensate, or pentanes plus that may be present in the pool if the application is granted,	
e) appropriate economic analyses, and	
f) pertinent reservoir studies.	The information for 8(f) is required only when the allowable was originally assigned for conservation reasons or when pool delineation is an issue.

Notification—Equity

The ERCB requires the information described below to establish who potentially adversely affected parties are and whether equity issues may exist. You are encouraged to carry out the notification described here. The ERCB reserves the right to advertise any application for its own purposes.

Requirements	Comments
1) A map showing	This information generally is required only when the allowable originally was assigned for conservation reasons or when pool delineation is an issue.
a) the zero edge of the pool,	
b) the status of each well completed in the pool, and	
c) the licensees in the pool and for 1600 m surrounding the pool that contains the well for which a change to allowable is requested.	Generally, only when allowables have been set for an entire pool for conservation reasons is the full level of notification referred to in 1(c) required. The 1600 m buffer around the pool is included to ensure that no offset licensees have a different interpretation of the pool. In most cases, affected parties are those considered by the ERCB to have a productive well in the same geological pool in a drilling spacing unit (DSU) immediately offsetting the subject well. If the allowable was established because the subject well is off target, generally only wells in the same geological pool that the subject well is off target towards are

Requirements	Comments
	considered to be affected, in accordance with ERCB *Interim Directive (ID) 94-2*. If the allowable was originally assigned for equity reasons, the offset licensees that requested that the allowable be set must be contacted.
2) A list of the parties notified regarding the proposed allowable change, the nature of the notification, the date of notification, and any comments received from the notified parties.	
3) A discussion of the effect that granting the application would have on the interests of other owners in the same pool.	

Unit 4 Disposal/Storage

4.1 Application for Class I-IV Disposal

4.1.1 Background

Disposal refers to the injection of fluids for purposes other than enhanced recovery or gas storage. In accordance with the *Oil and Gas Conservation Act*, Section 39(1)(c), ERCB approval of a scheme is required for the gathering, storage, and disposal of water produced in conjunction with oil and gas. Section 39(1)(d) requires ERCB approval of a scheme for the storage or disposal of any fluid or other substance to an underground formation through a well.

The ERCB classifies disposal wells based on the type of injection fluid. This classification system is outlined in ERCB *Directive 051*, Section 2.4.

4.1.2 When to Make This Application

If disposal of a fluid is required and you are certain that disposal at the proposed location will not cause an environmental or safety hazard and will not result in incremental hydrocarbon recovery, then you should make an application for disposal to the ERCB. As identified in ERCB *General Bulletin (GB) 2000-8,* the ERCB will approve a disposal well prior to completion of *Directive 051* requirements. However, injection may not commence until the requirements of *Directive 051* have been met, submitted, and approved by the ERCB.

4.1.3 How the ERCB Processes the Application

An application for disposal would likely be approved if the ERCB is satisfied that

- disposal will not impact hydrocarbon recovery,
- the disposal fluid will be confined to the injection formation,
- offset owners within 1.6 km of the disposal well(s) have been consulted and have no objections or concerns to the disposal scheme, and
- the applicant has the right to dispose into the requested formation.

4.1.4 Requirements for an Application for a Disposal Scheme

General

Requirements	Comments
1) A description of the proposed disposal scheme, including	
a) unique well identifier(s),	
b) disposal zone with zone top and base,	

Requirements	Comments
c) disposal perforations,	
d) disposal fluid class,	You should identify the class of the disposal fluid according to the system outlined in *Directive 051.*
e) anticipated daily disposal volume(s),	
f) injection pressure,	It is not desirable for disposal wells to exceed the fracture pressure because of possible isolation problems. If you are not providing formation fracture data or other information, such as a step-rate injectivity test, to support the requested maximum wellhead injection pressure, you should use *Directive 051*, Appendix 5: Maximum Allowable Wellhead Injection Pressures.
g) depth of the production packer, and	The packer should be set within 15 m of the perforation interval.
h) the base of the usable groundwater.	For groundwater information, see the Alberta Environment Groundwater Database available from ERCB Information Services. Produced water disposal cannot occur into the zone of origin or other formations identified as containing usable groundwater because there is no way to monitor or ensure that the produced water is not contaminated by the production process. For more information on this, see *General Bulletin (GB) 2000-8.*
2) A statement on why the proposed well is suitable for disposal.	
3) A statement on why the proposed disposal is required.	
4) An indication of whether you have applied for or obtained approval for related surface facilities.	Surface facility applications must be made in accordance with *Directive 056* or *Directive 058.*
5) Identification of the following:	
a) fluid type currently in the disposal interval (i.e., water, gas, or oil),	
b) confinement strata, if present,	

Requirements	Comments
c) porosity and permeability of the disposal zone, d) viscosity of the injected fluid and the reservoir fluid, and e) the distance between the proposed disposal well(s) and any hydrocarbon pool or accumulation.	
6) An interpreted and annotated log cross-section or representative well log(s) showing a) stratigraphic interpretation of the zone(s) of interest, b) interpretation of the fluid interfaces present, c) completions and treatments to the wellbore(s), with dates, d) cumulative production, e) finished drilling date and kelly bushing (KB) elevation, and f) the scale of the log readings.	

Conservation

If disposal is to occur into a hydrocarbon pool or an associated aquifer, it must be evident that it will not have a detrimental effect on ultimate hydrocarbon recovery from the pool.

If the proposed disposal well is more than 1.6 km from any hydrocarbon pool or accumulation, you may omit requirements relating to conservation.

Requirements	Comments
1) Identification of the ERCB-designated pool to receive the disposal fluid and/or any ERCB-designated pool within 1.6 km of the proposed disposal well.	
2) A statement on whether incremental hydrocarbon recovery is anticipated as a result of the proposed injection. If it is, state the incremental volume relative to the original oil in place (OOIP).	If incremental recovery is anticipated as a result of the proposed injection, consider applying for enhanced recovery rather than disposal.

Requirements	Comments
3) Discussion on the stage of depletion of the recipient pool.	
4) A statement on whether the pool contains an oil-water (o/w) or gas-water (g/w) contact. If it does, are the injection perforations below that contact?	If disposal occurs into a depleted pool or below the oil-water or gas-water contact, the negative impact of this disposal on ultimate recovery from the pool would usually be minimal.
5) An explanation of why the proposed disposal would not be detrimental to ultimate hydrocarbon recovery from the pool.	
6) Discussion on whether the proposed injection would have an impact on any producing wells in the pool. If it would, provide details. If it would not, support your view.	
7) If ERCB-approved water disposal is currently occurring in the pool, a list of those disposal wells and comments as to how the proposed disposal is compatible with the current disposal locations.	Multiple disposal wells in a pool require careful placement in order to avoid overinjection in any one part of the pool and to avoid trapping losses.
8) Discussion on whether there is an enhanced recovery scheme in the subject pool. If there is, explain why the proposed disposal cannot be incorporated into the scheme and why or how the proposed disposal is compatible with the current injection.	
9) A net pay isopach map of the pool, including both oil and gas if there is an associated pool.	
10) If pool delineation or fluid interface locations are based on structural interpretation, a structure contour map of the pool and offsetting area.	

Requirements	Comments
11) A tabulation of your interpreted net pay, porosity, and water saturations for each well in the pool, along with the cutoffs, methodology, formulas, and constants used.	If you do not supply tabulated well data for all wells in the pool, you must explain why (e.g., the area of application is very small relative to the entire pool).

Hydraulic Isolation

Disposal approvals specify the disposal zone and limit injection to that zone only. Migration of disposal fluids to other zones is highly undesirable. Therefore, a suite of logs is required for all injection wells in the province in order to confirm the absence of flow of injected fluid behind the casing. For more details on the logging requirements, see ERCB *Directive 051*. The ERCB will monitor to ensure that *Directive 051* requirements have been met prior to the commencement of injection.

Requirements	Comments
1) For disposal wells injecting hydrogen sulphide (H_2S) and Class I disposal, all completion logging, testing requirements, and associated discussion required by *Directive 051.*	All H_2S and Class I disposal wells must meet the *Directive 051* requirements prior to the wells going on injection and prior to the approval being issued. It is necessary to ensure that the integrity of the wellbore will prevent contamination of other zones and protect all groundwaters. A preliminary review of the application and a letter noting approval in principle pending successful *Directive 051* completion and proven injectivity may be issued if you desire to proceed with the application in two stages.
2) In order to prove hydraulic isolation for Class II-IV, provide the following: a) the completion logs and associated discussion required by *Directive 051* for all proposed disposal wells, **or** b) a discussion of the plans for complying with *Directive 051*, **or** c) a request for waiver of the *Directive 051* requirements, **or**	You should specify in the application whether the proposed disposal wells are in compliance with *Directive 051* requirements. If they are not, provide a discussion of the plans to bring the wells into compliance with *Directive 051* or indicate that a waiver is requested or has been approved. It is not necessary for *Directive 051* requirements to be met in order for a disposal scheme approval to be issued except when H_2S or Class I disposal is requested. All disposal well completions must meet the *Directive 051* requirements prior to the wells

Requirements	Comments
d) a copy of an ERCB letter waiving the *Directive 051* requirements.	going on injection in order to ensure that hydraulic isolation of the disposal interval exists at the wellbore and that the disposal fluid will enter the intended reservoir interval. The ERCB will permit injection of up to 500 m^3 of water to obtain the required isolation logs. If you have met *Directive 051* requirements for the proposed disposal wells, you must include the completion logs and associated discussions required by the directive. The ERCB will then handle all matters pertaining to the completion approval(s) concurrently with the scheme approval. **If you have not met *Directive 051* requirements, disposal may NOT commence until you have received a letter from the ERCB stating that the *Directive 051* requirements have been met and injection can commence.**
3) If you are requesting an extension to the three-month *Directive 051* submission date, provide a) the proposed submission date, and b) the reasons(s) for needing the submission date extension.	Disposal well approvals issued in advance of *Directive 051* requirements being met will contain a clause requiring that the *Directive 051* information be submitted within three months of the approval's issue date. If three months is not sufficient time to meet the *Directive 051* requirements, you must request an extension.
4) When submitting *Directive 051* information after the approval has been issued, you should provide the field and pool name, the disposal scheme approval number, and the well location(s).	If the *Directive 051* requirements are not submitted within the three months or other approved time frame, ERCB staff will rescind the approval or portion pertaining to the subject wells. For more information on submission requirements and the disposal approval process, see ERCB *General Bulletin (GB) 2000-8*.

Equity—Class II-IV Only

Disposal could occur into or near a multiownership pool, and owners' views on the impact of the disposal might vary. Note that, as identified in Tables 1 and 2 of the Resources Applications Notification Guidelines, notification requirements differ for waste and other disposal fluid types. For waste disposal applications, see the section on Oilfield or Industrial Waste Fluid Disposal below.

Requirements	Comments
1) A list of all potentially adversely affected parties (unit operators, approval holders, and/or well licensees) within a 1.6 km radius from the proposed disposal well(s) where the proposed disposal zone is known to be present.	If a pool is subject to unit operations or other approvals, in most cases you may notify the unit operator or approval holder on behalf of the relevant group having an interest in the pool. Otherwise, you should normally notify individual well licensees.
2) A statement as to whether you have contacted the above parties respecting the application and, if so, confirmation of nonobjection or specific details regarding objections or concerns.	If discussions concerning the application are continuing with offset operators, you should provide details as part of the application.
3) Evidence of your right to dispose into the proposed zone.	Proof of the right to dispose in a formation is as follows: • unleased Crown land—a letter of consent from the Crown, • Freehold lease land—consent from the Freehold mineral holder, and • leased by other than the applicant—a letter of consent from the lease holder.

Oilfield or Industrial Waste Fluid (Class I) Disposal

The following are further requirements pertaining to Class I disposal only. Note that generally you must obtain a surface facility approval from the ERCB Facilities Waste Management Section and/or Alberta Environment before the ERCB may issue a waste disposal well approval. For more information on waste facility applications, see ERCB *Directive 058*. You may obtain information on industrial waste facilities applications from the appropriate Alberta Environmental Corporate Regional office.

Requirements	Comments
1) Evidence of notification to and consent from the surface owner and/or occupant within a radius of 0.5 km from the proposed disposal well.	In view of the possible hazardous nature of waste disposal fluids, extra precautions are taken to ensure containment.
2) Evidence of notification to and consent from potentially adversely affected parties (unit operators, approval holders, well licensees, mineral lessees, and/or mineral lessors) within a 1.6 km radius of the proposed disposal well.	If a pool is subject to unit operations or other approvals, in most cases you may notify the unit operator or approval holder on behalf of the relevant group having an interest in the pool. Otherwise, you should normally notify individual well licensees.
3) Evidence of your right to dispose into the proposed zone.	Proof of the right to dispose in a formation is as follows: • unleased Crown land—a letter of consent from the Crown, • Freehold lease land—consent from the Freehold mineral holder, and • leased by other than the applicant—a letter of consent from the lease holder.
4) A discussion of the geological setting of the proposed disposal zone, including the integrity of the base and caprock and the stratification within the reservoir and reservoir parameters, giving vertical and horizontal permeabilities, thickness, and areal extent.	

Requirements	Comments
5) A discussion of the maximum expected area of influence surrounding the proposed well over the life of the scheme, including a discussion of any pressure gradients that exist as a result of past or current production or injection operations.	
6) Confirmation that all wells within the area of influence have been completed or abandoned in such a manner that they will not provide a path for the migration of the injected fluid or substance to another formation.	Oilfield or industrial waste fluids must **not** be disposed into a zone that has current production or the potential for future production.
7) In the case of slurry fracture injection of sand, details of the surface elevation monitoring that will be done within 800 m of the proposed disposal well to monitor the impact of slurry fracture injection of sand above the formation fracture pressure.	
8) Injection logs and analysis in accordance with *Directive 051*.	Confirmation of hydraulic isolation is required before the ERCB will issue an approval for waste disposal. This requirement differs from Class II-IV disposal because of a greater concern about waste contamination. For more details see *General Bulletin (GB) 2000-8*.
9) Evidence of compliance with the completion and testing requirements in *Directive 051*.	

4.2 Application for Acid Gas Disposal

4.2.1 Background

Acid gas disposal has become a cost-effective means to dispose of uneconomic quantities of hydrogen sulphide (H_2S) and carbon dioxide (acid gas) into underground formations. The formation types that the ERCB typically considers suitable for disposal are depleted hydrocarbon-bearing zones or unusable-water-bearing zones. The disposal of these waste by-products can reduce public concern resulting from sour gas production and flaring. Section 39(1)(d) of the *Oil and Gas Conservation Act* requires that no scheme for the disposal of any fluid to an underground formation shall proceed unless approved by the ERCB.

4.2.2 Requirements for an Application for an Acid Gas Disposal

Containment

Requirements	Comments
1) Your geological interpretation of the acid gas disposal formation involved, including a) net pay isopach map of the pool, b) where pool delineation or fluid interfaces are based on structural interpretation, a structural contour map of the pool and offsetting area, c) an interpreted and annotated log cross-section or representative well log(s), showing i) stratigraphic interpretation of the zone(s) of interest, ii) interpretation of the fluid interfaces present, iii) completions/treatments to the wellbore(s), with dates, iv) cumulative production, v) finished drilling date and kelly bushing (KB) elevation, and vi) the scale of the log readings, and	It is necessary to determine that there will be containment of the disposal fluid within a defined area and geologic horizon to ensure that there is no migration to hydrocarbon-bearing zones or groundwaters. To address this issue, you must provide a suite of geological evidence.

Requirements	Comments
d) tabulation of your interpreted net pay, porosity, and water saturation for each well in the pool, along with the cutoffs, methodology, formulas, and constants used.	
2) For bounding formations, information including a) continuity and thickness of base and caprock, b) lithology, c) integrity of the base and caprock, d) if fracturing is evident, explanation of how containment can be assured, and e) a comment on the stratigraphic, structural, or combination reservoir trap type and its containment features.	

Reservoir

Requirements	Comments
1) Analysis of the native reservoir fluid(s).	The impact of the disposal fluid on the reservoir rock matrix, native fluid, and the pressure variations subjected to the disposal zone requires that you address phase behaviour, pressure, and migration issues.
2) Acid gas properties, including a) composition, b) viscosity, density, gas injection formation volume factor, and compressibility factors, and c) phase behaviour through the range of pressures and temperatures to which the injected fluid will be subjected.	
3) An analysis of laboratory testing for	

Requirements	Comments
determining injected fluid interaction with matrix, caprock matrix, and native fluid(s).	
4) Migration calculation showing radius of influence, as well as a discussion if migration could occur due to displacement, gravity, fingering, etc. (not required for depleted reservoirs less than two sections in areal extent).	
5) Complete pressure history of the pool, with material balance calculations if proposed disposal zone is a depleted hydrocarbon pool.	
6) Bottomhole injection pressure, maximum sandface pressure, caprock threshold pressure, fracture propagation pressure, and formation fracture pressure.	It is not desirable for disposal wells to exceed the fracture pressure because of possible isolation problems. If you are not providing formation fracture data or other information, such as a step-rate of injectivity test, to support the requested maximum wellhead injection pressure, use *Directive 051*, Appendix 5.
7) Injectivity of the reservoir, proposed daily maximum injection rate, cumulative disposal volume, and expected life of the scheme.	

Hydraulic Isolation

Requirements	Comments
1) For acid gas disposal wells injecting H_2S, all completion data, well logs, testing requirements, and associated discussion, as described in *Directive 051*.	All H_2S disposal wells must meet the *Directive 051* requirements prior to the wells going on injection and prior to the approval being issued. It is necessary to ensure that the integrity of the wellbore will prevent contamination of other zones and protect all groundwaters. The ERCB may issue a preliminary review of the application and a letter noting approval in principle pending successful *Directive 051* completion and proven injectivity if you desire to do the application in two stages.

Requirements	Comments
2) For non-H_2S gas disposal provide a) the completion logs and associated discussion required by *Directive 051* for all proposed disposal wells, or b) a discussion of the plans for complying with *Directive 051*, or c) a request for waiver of the *Directive 051* requirements, or d) a copy of an ERCB letter waiving the *Directive 051* requirements.	You should specify in the application whether the proposed disposal wells are in compliance with *Directive 051* requirements. If they are not, provide a discussion of the plans to bring the wells into compliance with *Directive 051* or indicate that a waiver is requested or has been approved. It is not necessary for *Directive 051* requirements to be met in order for a disposal scheme approval to be issued except when H_2S is to be injected. All disposal well completions must meet the *Directive 051* requirements prior to the wells going on injection in order to ensure that hydraulic isolation of the disposal interval exists at the wellbore and that the disposal fluid will enter the intended reservoir interval. The ERCB will permit injection of up to 500 m^3 of water to obtain the required isolation logs. If the proposed disposal wells meet *Directive 051* requirements, you must include the completion logs and associated discussions required by the directive. The ERCB will then handle all matters pertaining to the completion approval(s) concurrently with the scheme approval. The ERCB will review the scheme shortly after the approval is issued and undertake enforcement action if disposal has not commenced as specified in the approval. **If you have not met *Directive 051* requirements, disposal may NOT commence until you have received a letter from the ERCB stating that the *Directive 051* requirements have been met and injection can commence.**

Requirements	Comments
3) If requesting an extension to the three-month period for *Directive 051* submission date, provide a) the proposed submission date, and b) the reason(s) for needing the submission date extension.	Disposal well approvals for non-H_2S gas injection issued in advance of *Directive 051* requirements being met will contain a clause requiring that the *Directive 051* information be submitted within three months of the approval's issue date. If three months is not sufficient time to meet the *Directive 051* requirements, you must request an extension. If the *Directive 051* requirements are not submitted within the three months or other approved time frame, ERCB staff will rescind the approval or portion pertaining to the subject wells. For more information on submission requirements and the disposal approval process, see *General Bulletin (GB) 2000-8.*
4) When submitting *Directive 051* information after the approval has been issued, provide the field and pool name, the disposal scheme approval number, and the well location(s).	
5) Provide the following information for either 1) all the wells in the pool if disposal is into a depleted hydrocarbon pool or 2) all the wells within the disposal well section and adjoining sections if disposal is into an aquifer system: a) well location, b) status of well, c) completion intervals, and d) all casing information.	There must be hydraulic isolation between the disposal fluid and any other wellbores drilled into or through the disposal zone.

Notification—Equity and Safety

Requirements	Comments
1) Evidence of your right to dispose into the proposed zone.	Proof of the right to dispose in a formation is as follows: • unleased Crown land—a letter of consent from the Crown, • Freehold lease land—consent from the Freehold mineral holder, and • leased by other than the applicant—a letter of consent from the lease holder.
2) Provide a) a map showing the boundaries of the disposal pool or the area within the disposal section and the adjoining offset sections up to a 1.6 km radius with well licensees, mineral right lessees, and lessors recorded, and b) a statement confirming that all potentially adversely affected parties that may be impacted have been notified and giving any details of outstanding objections or concerns to the proposed scheme.	Disposal could occur into or near a multiownership pool, and owners' views on the impact of the disposal might vary. You must notify all lessors, lessees, and well licensees within the depleted hydrocarbon pool OR within the disposal section and the adjoining offset sections up to a 1.6 km radius if disposal is into an aquifer system. If a pool is subject to unit operations or other approvals, in most cases you must notify the unit operator or approval holder on behalf of the relevant group having an interest in the pool. Otherwise, you should notify individual well licensees. If discussions concerning the application are continuing with offset operators, you should provide details as part of the application.
3) If the injected fluid contains any H_2S, a statement indicating that notification of the scheme for emergency response plan (ERP) purposes has been made to all potentially adversely affected parties. Include the details of any outstanding objections or concerns from the notified parties.	If facilities may pose a risk to the public, ERP requirements must be met prior to commencement of operations. Generally, an ERP is required if a risk assessment indicates that there are members of the public within a defined hazard area. ERPs are approved and reviewed for compliance by the Operations Group of the ERCB. Contact Production Operations (403-297-2625) if further information is needed.

4.3 Application for Underground Gas Storage

4.3.1 Background

The storage of gas into underground hydrocarbon reservoirs can be for production-motivated reasons or commercial operations. Production-motivated schemes are usually characterized by the temporary storage of gas occurring at or near the producing pools. They can allow for the more efficient use of production and processing facilities and may also be of benefit in market-related situations. Commercial gas storage schemes are designed to provide an efficient means of balancing supply with a fluctuating market demand. These schemes store third-party nonnative gas, allowing marketers to take advantage of seasonal price differences, effect custody transfers, and maintain reliability of supply. Gas from many sources may be stored at commercial facilities under fee-for-service, buy-sell, or other contractual arrangements.

The ERCB regulates gas storage operations to ensure that all gas conservation, equity, environment, and safety issues are addressed and to maintain up-to-date estimates of provincial gas reserves and deliverability.

4.3.2 Terms of Application

An application for approval of a new scheme or amendment to an existing scheme for the underground storage of gas is made under Section 39(1)(b) of the *Oil and Gas Conservation Act*. It must initially include the requirements detailed below and possibly other information if ERCB staff find that necessary for evaluation purposes.

4.3.3 Application Requirements for Underground Gas Storage

Conservation

The ERCB is concerned about any reserve losses that may occur through gas storage. Reservoir containment of the gas, gas trapping by water, excessive water production, and the dilution of produced gas by acid gas are the primary issues that need to be evaluated.

Requirements	Comments
1) Your geological interpretation of the pool, including	
a) a net pay isopach map of the pool, including both oil and gas if there is an associated pool,	If the pool has a good geological history that is well defined, only one representative well log is likely required. However, if the pool is complex and has had recent development, you should provide several well logs to a detailed cross-section of the pool. If the geological interpretation submitted is not adequately done, processing delays could result.
b) if pool delineation or fluid interface locations are based on structural interpretation, a structure contour map of the pool and offsetting area,	
c) an interpreted and annotated log cross-section or representative well log(s) showing	

Requirements	Comments
i) stratigraphic interpretation of the zone(s) of interest, ii) interpretation of the fluid interfaces present, iii) completions and treatments to the wellbore(s), with dates, iv) cumulative production, v) finished drilling date and kelly bushing (KB) elevation, and vi) the scale of the log readings, and d) a tabulation of your interpreted net pay, porosity, and water saturation for each well in the pool, along with the cutoffs, methodology, formulas, and constants used.	
2) Maximum bottomhole injection pressure and maximum average reservoir pressure.	This information defines the upper limit to the operating pressures of the scheme.
3) Complete tabulated pressure history of the pool (date, well, type of test, stabilized pressure), along with a P/Z versus cumulative gas production plot if the pool is a nonassociated gas pool, or material balance calculations if storage is into a gas cap in communication with an oil leg.	This history indicates pressure support from the aquifer and how the reservoir may react to storage.
4) Gas analysis of the native reservoir fluid and the proposed injected gas stream(s).	This describes what the compositions of the gases are before they become mixed.
5) Discussion of how the storage of gas will be consistent with sound conservation practices.	
6) If at any time during storage, the average reservoir pressure will exceed the initial pool pressure (i.e., delta pressuring is being applied for), then reservoir containment of gas becomes a concern and the following are required:	

Requirements	Comments
a) for the storage formation, a list of the formation fracture pressure and fracture propagation pressure, with a description of how they were determined, and	It is necessary to determine if the storage formation will be fractured and/or the extent to which the fractures may spread.
b) for the bounding formations,	
i) the continuity and thickness of base and caprock,	
ii) lithology,	
iii) evidence of fracturing,	
iv) a comment on the integrity of the base and caprock (stratigraphic, structural, or combination) and its containment features, and	
v) caprock threshold pressure.	
7) If there is an active aquifer system present, the trapping of gas displaced into the rising aquifer is a concern and the following are required:	
a) any measured changes in the gas/water contact, and	This will indicate where trapped gas can occur.
b) impact from the aquifer, including quantifying the amount of displaced gas that will be trapped.	This will state the impact by the aquifer and indicate whether it is a concern for storage.
8) If there are wells in the pool that have produced or are producing with high water/gas ratios (e.g., over $100\ m^3/10^6\ m^3$), loss of wells due to water coning or channelling is a concern and the following are required:	
a) production history for the wells with high water/gas ratios, and	This will show where the water problems may be occurring in the pool and how they were/are handled.
b) a discussion on how the water production is controlled.	

Pool Reserves and Deliverability Information

The ERCB updates and publishes pool reserves data annually. For this reason it needs to understand the operations at the pool. Commercial gas storage pools are also listed in the annual reserves report, but rather than showing the remaining reserves for these pools, the storage capacity and maximum deliverability are published.

Requirements	Comments
1) An estimate of the initial gas and oil volumes in place.	This information will indicate the initial producible gas reserves.
2) An estimate of the gas and oil recovery factors.	
3) A description of the methods used in determining the initial gas/oil volumes in place and the respective recovery factors (e.g., material balance, volumetric analysis, model study, and a comparison of analog pools).	
4) The supporting data used in determining the first two points as outlined above and the sources of the data (e.g., pressure/volume/temperature [PVT] properties and source, pressure data and source).	
5) Remaining native gas in place and the cushion gas required for storage operations.	It is important to determine the remaining native gas in place before storage commences and what additional gas needs to be injected to meet the cushion gas requirements.
6) Working gas volumes.	This information will determine the storage capacity of the pool.
7) Deliverability and injectivity of the reservoir under the range of operating conditions.	This information will indicate the production and injection capabilities of the pool.

Equity

Equity is an important issue for gas storage pools, since competitive gas production would be detrimental to storage scheme operations. Therefore, it is advisable that you own all of the mineral right leases in the pool and adjoining sections or at least have a production-sharing agreement and written consent from the other owners that could be impacted.

It is also strongly advised that if some land is still available for sale, you purchase this land before considering the pool for storage.

The lessors must also provide consent for storage, since a special royalty agreement covering the remaining producible gas reserves may be required.

If all potential equity concerns are addressed before the scheme is approved, a costly and complicated hearing process may be avoided in the future.

You must notify all lessees and lessors within the area of the storage pool and adjoining offsetting sections. Notification must cover all zones, including those that either underlie or overlie the storage pool. You must also notify all well licensees in the pool.

Requirements	Comments
1) A map showing the boundaries of the storage pool (both ERCB pool outline and your pool outline), along with the well licensees and mineral right lessees and lessors that are within these boundaries, as well as those that lie outside in the offsetting sections.	
2) A statement confirming that you have notified all parties that may be impacted, either negatively or positively, and that they have no objection or concerns to the proposed storage scheme (this includes, but is not limited to, the groups listed in item 1 above).	
3) A list of all objections or concerns received.	
4) If you do not hold all of the mineral right leases in the pool, an indication of the area in the pool where you do not own the mineral right leases and an explanation of why you have not purchased them.	It is important to understand the risk involved with a competing company buying mineral rights and drilling a productive well.

Environment and Safety

The ERCB is also responsible for environmental and safety issues when approving gas storage schemes. Therefore all injection wells must meet the requirements of ERCB *Directive 051* to ensure that the integrity of the wellbore will prevent contamination of other zones and to protect all groundwaters.

Requirements	**Comments**
1) For gas storage wells injecting hydrogen sulphide (H_2S), all completion data, well logs, testing requirements, and associated discussions, as described in *Directive 051*.	All gas storage wells injecting gas containing H_2S must meet *Directive 051* requirements prior to the wells going on injection and prior to the approval being issued. It is necessary to ensure that the integrity of the wellbore will prevent contamination of other zones and protect all groundwaters. A preliminary review of the application and a letter noting approval in principle pending successful *Directive 051* completion and proven injectivity may be issued if you desire to do the application in two stages.
2) For non-H_2S gas storage, provide a) the completion logs and associated discussion required by *Directive 051* for all gas storage wells, or b) a discussion of your plans for complying with *Directive 051*, or c) a request for waiver of the *Directive 051* requirements, or d) a copy of an ERCB letter waiving the *Directive 051* requirements.	You should specify in the application whether the proposed gas storage wells are in compliance with *Directive 051* requirements. If they are not, provide a discussion of the plans to bring the wells into compliance with *Directive 051* or indicate that a waiver is requested or has been approved. It is not necessary for *Directive 051* requirements to be met in order for a gas storage scheme approval to be issued except when H_2S is to be injected.
3) When requesting an extension to the three-month period for *Directive 051* submission, provide a) the proposed submission date, and b) the reason(s) for needing the submission date extension.	For gas storage scheme approvals for non-H_2S gas injection issued in advance of *Directive 051* requirements being met, the ERCB will expect you to submit the *Directive 051* information within three months of the approval's issue date. If three months is not sufficient time to meet the *Directive 051* requirements, you must request an extension.

Requirements	Comments
4) When submitting *Directive 051* information after the approval has been issued, provide the field and pool name, the disposal scheme approval number, and the well location(s).	If you do not submit the *Directive 051* requirements within the three months or other approved period, the ERCB will rescind the gas storage approval or portion referencing the specific well(s). If *Directive 051* has been met for the proposed gas storage wells, you must include the completion logs and associated discussion required by the directive. The ERCB will then handle all matters pertaining to the completion approval(s) concurrently with the scheme approval. **If you have not met *Directive 051* requirements for the proposed storage well(s), in no case shall injection to the gas storage well(s) commence until you have received a letter from the ERCB indicating that *Directive 051* requirements have been met.**
5) If the injected fluid contains any H_2S, a statement is required indicating that notification of the scheme for emergency response plan (ERP) purposes has been made to all potentially adversely affected parties. You must include the details of any outstanding objections or concerns from the notified parties.	Where facilities may pose a risk to the public, ERP requirements must be met prior to commencement of operations. Generally, an ERP is required if a risk assessment indicates that there are members of the public within a defined hazard area. ERPs are submitted to the Emergency Planning and Assessment Section to ensure that requirements to *Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry* have been met. Questions may be directed to the EPA Help line at 403-297-2625.

Monitoring Scheme Operation

After a storage scheme has been approved and is placed into operation, the performance of the scheme becomes an issue. The ERCB is interested in ensuring that the scheme will be operated within the conditions of the approval.

Requirements	Comments
1) A discussion of the monitoring program, including the frequency and method of measuring the bottomhole and/or top-hole pressures.	This discussion will determine how the scheme will be operated to ensure that the approval conditions will not be exceeded.

5. Corporate Changes

Unit 5 Corporate Changes

5.1 Change in Name of Approval Holder

5.1.1 Background

In accordance with Section 15.080 of the *Oil and Gas Conservation Regulations*, the operator of a scheme approved under Section 39 of the *Oil and Gas Conservation Act* should apply to amend the approval to show the name change that has occurred since the scheme was approved.

5.1.2 Requirements for an Application for a Change in Name of Approval Holder

Requirements	Comments
1) Approval number.	As an operator doing business in Alberta, it is your responsibility to keep the appropriate documents current.
2) Field and pool named on the approval.	
3) Type of scheme.	
4) a) Evidence of the change in name, or b) details on when such evidence was filed with the ERCB.	For a name change to multiple schemes, you may attach a list of the approvals, including the numbers, field and pool, and type of scheme. The ERCB requires the current scheme approval name so that staff can effectively conduct appropriate surveillance of the scheme and can update documents and publications made available to the public and industry.

5.2 Change of Approval Holder

5.2.1 Background

In accordance with Section 15.080 of the *Oil and Gas Conservation Regulations*, the operator of a scheme approved under Section 39 of the *Oil and Gas Conservation Act* should apply to amend the approval to show the change of holder of the approval if the scheme has been sold or divested.

5.2.2 Requirements for an Application for a Change of Approval Holder

Requirements	Comments
1) Approval number.	It is important that companies purchasing new properties in Alberta understand the terms and conditions of the scheme and that they update the appropriate ERCB documents. This also enables ERCB staff to effectively conduct appropriate surveillance of the scheme. You may use the Transfer of Approval form in Appendix D.
2) Field and pool named on the approval.	
3) Statements by the present holder and the proposed new holder agreeing to the change.	
4) A statement by the proposed new holder stating the circumstances giving rise to the application.	
5) A statement by the proposed new holder stating that he/she is aware of the details of the scheme and is prepared to carry out the scheme.	
6) If the present holder no longer exists, evidence that the proposed new holder is the proper person/company to assume responsibility for the scheme, with a Gazette reference that the present holder is no longer in existence.	

Unit 6 Gas and Ethane Removal

6.1 Background

The removal of natural gas from the province of Alberta is governed by the *Gas Resources Preservation Act* (*GRPA*). A major reason for gas removal permits is to control the amount of gas leaving the province and thereby ensure that Albertans have an adequate supply. The ERCB completes an annual calculation that indicates whether or not there is gas available for inclusion in gas removal permits, taking into account a 15-year supply for the core Alberta market and obligations resulting from existing gas removal permits. *Report 87-A: Gas Supply Protection for Alberta*, available from ERCB Information Services, presents the ERCB's policies on gas supply matters. While the forms and procedures in this document have been superseded, the report continues to provide valid information regarding gas supply protection for Alberta.

As set out in the *GRPA*, there are two types of gas removal permits:

- Short-term gas removal permits involve the removal of not more than 3 billion cubic metres (m^3) of gas over a period of not more than two years. These permits may be used for any market.
- Long-term gas removal permits involve the removal of gas in volumes greater than 3 billion m^3 of gas or permit terms longer than two years. These permits are market specific and may be used only to serve the market(s) described in the applications that resulted in the permits.

This directive replaces *Informational Letter (IL) 96-5: Requirements for Applications for Permits to Remove Gas from Alberta*. The directive updates existing requirements but does not introduce any changes in gas removal policy or new requirements for applications for the removal of natural gas. Additionally, the directive sets out the requirements for ethane removal permits. These requirements were not previously set out in any document but were handled on an ad hoc basis.

6.2 When to Make This Application

Under the *GRPA*, any party wishing to remove natural gas or ethane out of Alberta must apply to the ERCB under Section 2 of the *GRPA* for a permit to authorize such removal of gas. No ERCB permits are required to take propanes, butanes, pentanes, other natural gas liquids, or oil out of Alberta. No permits from the ERCB are required to import gas into the province.

If there are corporate changes such that the party desiring to use a permit is not the permittee named in the permit, an application must be filed to amend the permit holder name in the permit.

6.3 How the ERCB Processes the Application

Applications for gas and ethane removal permits and for amendments of existing gas removal permits must be filed using one of the application forms included in Appendix G.

6.3.1 Short-Term Gas Removal Application Form

This form must be used to apply for a new permit or to amend an existing permit authorizing the removal of natural gas of not more than 3 billion m^3 of gas over a period of not more than two years.

The ERCB's practice is to allow one short-term gas removal permit per company. When the ERCB receives a completed application form, it reviews the information provided to determine if it is consistent with the standard ERCB practices and the *GRPA*, as discussed in this section. An applicant is not required to give notification to any party or advertise its intent to apply for new short-term gas removal permit or for an amendment to an existing short-term permit. The ERCB does not issue any notice of these applications.

If the application is acceptable, the ERCB approves it through the issuance of a gas removal permit. Any party may obtain information respecting when and how many short-term gas removal permits are issued by reviewing the ERCB publication *ST48: Alberta Gas Removal and Related Applications*, which notes new permits issued in any month, together with existing valid permits.

6.3.2 Long-Term Gas Removal Application Form

This form must be used to apply for a new permit or to amend an existing permit authorizing the removal of natural gas in volumes greater than 3 billion m^3 of gas or for permit terms longer than two years.

The ERCB's standard practice is to allow each company to hold one long-term gas removal permit. Some companies were able to obtain numerous long-term gas removal permits prior to the ERCB implementing this practice. In these cases, the ERCB will not allow the company to obtain any further separate long-term removal permits, but will require the company to consolidate existing permits into one permit to serve the existing markets, as well as specific new markets.

When the ERCB receives a completed application form, it reviews the information provided to determine if it is consistent with the standard ERCB practices and the *GRPA*, as discussed in this section. An applicant is not required to give notification to any party or advertise its intent to apply for a long-term gas removal permit or for an amendment to an existing long-term permit. However, as a general practice, the ERCB publishes notice of any long-term gas removal application in major provincial newspapers as part of processing the application, since these applications may affect the public interest. If the ERCB receives objections to an application, the ERCB may hold a public hearing to consider the application.

When approval of the application is granted, the ERCB proceeds with the steps required to issue the new long-term gas removal permit or the amendment to a long-term gas removal permit. This includes obtaining the approval of the Lieutenant Governor in Council to issue the permit.

As in the case for a short-term gas removal permit, any party may obtain information respecting when and how many long-term gas removal permits are issued by reviewing the ERCB publication *ST48: Alberta Gas Removal and Related Applications*, which notes new permits issued in any month, together with existing valid permits.

6.3.3 Short-Term Ethane Removal Application Form

This form must be used to apply for a new permit or to amend an existing permit authorizing the removal of ethane of not more than 3 billion m^3 of gas over a period of not more than two years.

The ERCB's practice is to allow one short-term ethane removal permit per company. When the ERCB receives a completed application form, it reviews the information provided to determine if it is consistent with the standard ERCB practices and the *GRPA*, as discussed in this section. An applicant is not required to give notification to any party or advertise its intent to apply for a short-term ethane removal permit or for an amendment to an existing permit. However, depending on the current supplies of ethane in the province at any time, the ERCB may issue notice of the ethane removal permit application in major provincial newspapers as part of processing the application. If the ERCB receives objections to an application, the ERCB may hold a public hearing to consider the application.

When approval of the application is granted, the ERCB proceeds with the steps required to issue the ethane removal permit or the amendment to an ethane removal permit. This includes obtaining the approval of the Minister of Energy to issue the permit.

As in the case for permits to remove natural gas from Alberta, any party may obtain information respecting when and how many ethane removal permits are issued by reviewing the ERCB publication *ST48: Alberta Gas Removal and Related Applications*, which notes new permits issued in any month, together with existing valid permits.

6.3.4 Long-Term Ethane Removal Application Form

No application form for a permit authorizing the removal of ethane in volumes greater than 3 billion m^3 over permit terms longer than two years has been constructed, as the ERCB does not anticipate any requests of this type in the near term.

6.4 Reporting Natural Gas and Ethane Removed from Alberta

A key regulatory mandate of the ERCB, as set out in Section 2(f) of the *Energy Resources Conservation Act*, is to provide for the recording and timely and useful dissemination of information regarding the energy resources of Alberta. Accordingly, upon the commencement date of a permit for the removal of natural gas or ethane, the company holding the permit, or its agent, must file a monthly report with the ERCB stating the volume of gas removed and other related information. The gas removal permit data are captured electronically by the Gas Removal Data (GRD) system. All parties must file data electronically; the ERCB will not accept any gas removal permit data in a paper format. More information on the reporting of gas removed from Alberta under a permit is provided in *Bulletin 2006-42: Gas Removal Data System Compliance Process.* Questions on the reporting of gas removed from Alberta may be directed to the ERCB's Economics Group at (403) 297-5836.

Failure to report under a gas removal permit or a contravention of the terms of a permit will result in the ERCB taking enforcement action in accordance with ERCB *Directive 019: ERCB Compliance Assurance—Enforcement.*

6.5 Requirements for an Application for a Short-Term Gas Removal Permit

Requirements	Comments
1) Short-Term Gas Removal Application form	You should file your application for a short-term gas removal permit at least one month prior to the desired effective date of the permit. The Short-Term Gas Removal Application form shown in Appendix G must be used to request a new gas removal permit or an amendment to an existing gas removal permit. The ERCB will accept an application only if it is filed using the form. An applicant is not required to give notification to any party or advertise its intent to apply for a new short-term gas removal permit or for an amendment to an existing permit.
2) Part A (for a new permit)	Complete Part A of the form if you are applying for a new permit. If you are applying for an amendment to an existing permit, leave Part A blank. The volume of natural gas proposed for removal from Alberta entered on the application form in Part A must be expressed as the total volume in m^3 proposed for removal from Alberta over the entire term of the permit. This volume must not be expressed as a daily or annual volume. The maximum volume that may be removed under a short-term permit, including amendments, is 3 billion m^3. The maximum term for a short-term gas removal permit is two years (e.g., from November 1, 2006, to October 31, 2008). A permit may be made effective on the date it is issued or at some future date. However, the ERCB has no legislative authority to backdate a permit.
3) Part B (for an amendment to an existing permit)	You may apply to amend the volume, term, and/or holder of an existing permit. Only that portion of the form pertaining to the desired amendment should be filled out; e.g., if you desire to amend only the term of a permit, leave the other portions of Part B blank.

Requirements	Comments
	If an existing short-term gas removal permit has authorized the removal of a volume of gas less than 3 billion m^3, the permit may be amended to increase the volume up to 3 billion m^3. However, if you have an existing short-term gas removal permit authorizing the removal of 3 billion m^3 of gas and you have removed that volume of gas before the permit termination date, you cannot amend the permit to take out additional volumes of gas, as the *GRPA* limits the volume allowed for removal under a short-term permit, including amendments to the permit, to 3 billion m^3. In this scenario, you must apply for a new permit. The term of a permit may be rolled to allow a further maximum term of two years, but only if the volume of gas removed under the permit and all amendments does not exceed 3 billion m^3. To request any change in the named permit holder, check the box in front of the words "Change of permit holder" and the box in front of the statement beginning "The proposed permit holder…." It is very important to check this agreement box, as this confirms that the proposed permit holder is fully prepared to take on the obligations of the previous permit holder with respect to the permit. The ERCB will not process a request to change the name on a permit unless this box has been checked.
4) Part C (for the rescission of a permit)	Complete this portion of the form when you want to rescind an existing permit. Sometimes an existing permit should be rescinded at the same time a new permit is requested. For example, if you are requesting a new permit because you have removed the maximum volume of gas allowable of 3 billion m^3 before the termination of a permit and you want to continue removing gas from Alberta, you must apply for a new permit using Part A of the form. However, you should also ask for the rescission of the current permit, because the permit will remain active until it either reaches its

Requirements	Comments
	termination date or is rescinded, even though you can no longer use it because of the volume limitation. As long as a permit is active, you must continue filing reports for that permit; therefore, if the permit that you can no longer use is rescinded, you no longer need to file any reports for it.

6.6 Requirements for an Application for a Long-Term Gas Removal Permit

Requirements	Comments
1) Long-Term Gas Removal Application form	The Long-Term Gas Removal Application form shown in Appendix G must be used to request a new gas removal permit or an amendment to an existing gas removal permit. The ERCB will accept an application only if it is filed using the form. An applicant is not required to give notification to any party or advertise its intent to apply for a long-term gas removal permit or for an amendment to an existing permit.
2) Change of permit holder	To request any change in the named permit holder, check the box in front of the words "Change of permit holder" and the box in front of the statement beginning "The proposed permit holder…." It is very important to check this agreement box, as this confirms that the proposed permit holder is fully prepared to take on the obligations of the previous permit holder with respect to the permit. The ERCB will not process a request to change the name on a permit unless this box has been checked.
3) Permit(s) No. to be rescinded	Complete this portion of the form only when you want to rescind an existing permit; otherwise, leave it blank.
4a) Total volume of gas proposed for removal	If you wish to amend an existing long-term gas removal permit to add a new market with an associated new volume, fill out the "Existing volume authorized" line to reflect the volume currently authorized for removal under the existing permit. The "Proposed volume

Requirements	Comments
	authorized" line should reflect the existing volume authorized plus the new volume to be added. The volume of natural gas proposed for removal from Alberta must be expressed as the total volume in m^3 proposed for removal from Alberta over the entire term of the permit. This volume must not be expressed as a daily or annual volume.
b) Gas required for fuel to transport gas from Alberta	A description of how fuel gas has been accounted for is required. Normally, such gas would be accounted for in the new volumes of gas to be removed from Alberta entered on the "Proposed volume authorized" line.
5) Term of permit	If you wish to amend an existing long-term gas removal permit to add a new market with an associated new volume and the existing permit term covers the term of the new sale, fill out the "Existing term and commencement date" line on the form. Fill in the "Proposed term and commencement date" line only if the term of the existing permit does not accommodate the new market. If you are applying for a new permit, leave the "Existing term and commencement date" line blank and only fill in the "Proposed term and commencement date" line. As discussed in *Report 87-A: Gas Supply Protection for Alberta*, the ERCB normally grants permits with a maximum term of 15 years, except in special circumstances. Therefore, if the proposed term is greater than 15 years, you must attach a discussion to your application describing how the circumstances justify the requested term, including an indication as to whether the proposed gas removals could proceed under the 15-year permit and if not, why not. A permit may be made effective on the date it is issued or at some future date. However, the ERCB has no legislative authority to backdate a permit.

Requirements	Comments
6) Name of proposed market(s), and the location and type of end-use customer(s) to be served under the permit	The name of the proposed market is the company to which the gas would initially be sold, as well as the names of any other companies that would acquire the gas prior to the final sale of the gas to the end-use customer. The location of the end-use customer is province(s) in Canada and/or or state(s) in the United States. The type of end-use customer could be industrial, commercial, residential, and electrical generation markets.
7) Are arrangements in place for transporting the applied-for gas from the Alberta receipt point(s) to the intended end-use customer(s)?	If all transportation arrangements are in place, check the Yes box, and proceed to the next item. However, if some or all of the transportation arrangements are not in place, check the No box, and explain what arrangements have been made and when it is anticipated that any new facilities required would be completed. Name the pipelines ultimately leading to the end-use market, and state what has been done to ensure that transportation arrangements will be in place. While transportation arrangements do not have to be complete in order to obtain a long-term gas removal application, steps should have been taken to acquire them.
8) Provide a summary of the pricing arrangements and how they were determined for the applied-for gas. Comment on any provisions to ensure that prices continue to reflect market conditions throughout the term of the permit.	The ERCB does not require specific price information; however, the method of determining the price reflects whether such arrangements are in the public interest of Albertans. The ERCB considers prices that adapt to constantly changing conditions and reflect a fair market value throughout the term of a permit regardless of the absolute market price to be in the public interest.
9) Discuss how the applied-for removal of gas would be in the Alberta public interest.	This should be a general discussion on provincial public interest matters.
10) Attach a table in the required format of the lands/zones that would supply the permit or amended permit, including • the legal description of all of the lands involved,	The ERCB's policy is that a party holding a long-term permit must have sufficient gas reserves under control to supply the entire requested volume of the permit. You must supply a list of lands and zones that

Requirements	Comments
• the zone or zones under your company's control for the lands in question, and • the working interest ownership under your company's control for the lands/zones.	will supply the requested permit. Typically, a company files one corporate reserves pool (CRP) with the ERCB that lists the lands and zones that supply all of its ERCB permits. To simplify this step of the application process, an electronic file of the CRP should be set up with the ERCB prior to filing a long-term gas removal application. To obtain the specific format required for the CRP to be filed, contact the ERCB's Business Operations and Development Group at 403-297-2884. After setting up a CRP with the ERCB, request an ERCB Reserves Under Control Table that lists the volume of gas reserves that the ERCB recognizes for the specific land, zone, and working interest information provided. Review this table carefully. If you disagree with the gas volumes listed on the ERCB table associated with a specific section or note that no volumes have been listed for a section, you may request that the ERCB review the reserves associated with the specific section. This may be done by completing the form EG-31(b)-83-1, included in Appendix H. Attach appropriate isopach maps and supporting information to the form. You should have the results of any requests made in this regard on a revised ERCB Reserves Under Control Table prior to filing any long- term gas removal application. If you already have filed with the ERCB a CPR that is serving a permit and you are applying to amend an existing long-term permit to add a new market, the CRP must have been updated within the last calendar year. Attach the ERCB Reserves Under Control Table to the application. This table must contain up-to-date data and have been produced shortly before the filing of the long-term gas removal application. The table will serve as a public record of the location of the lands that will supply the applied-for gas removal.
11) Attach a summary of the total gas reserves volume associated with the lands serving the	The adjusted total gas volume listed on the ERCB Reserves Under Control Table noted in

Requirements	Comments
proposed permit, together with a list of all commitments that would be served by the reserves portfolio involved, including • the proposed permit, • other permits (specify the number of each existing permit, as well as remaining authorized commitment), • intra-Alberta commitments (such as industrial, commercial, or residential contracts or corporate warranties to other companies), and • any other commitments.	item 10 is the volume that the ERCB will use in determining whether you have sufficient gas reserves under control to supply the proposed gas removal. The ERCB will compare the total volume noted on the table against the existing obligations you have for the gas in the CRP.

6.7 Requirements for an Application for a Short-Term Ethane Removal Permit

Requirements	Comments
1) Short-Term Ethane Removal Application form	The Short-Term Ethane Removal Application form as shown in Appendix G must be used to request a new ethane removal permit or an amendment to an existing ethane removal permit. The ERCB will accept an application only if it is filed using the form. An applicant is not required to give notification to any party or advertise its intent to apply for a short-term ethane removal permit or for an amendment to an existing permit.
2) Change of permit holder	To request any change in the named permit holder, check the box in front of the words "Change of permit holder" and the box in front of the statement beginning "The proposed permit holder…." It is very important to check this agreement box, as this confirms that the proposed permit holder is fully prepared to take on the obligations of the previous permit holder with respect to the permit. The ERCB will not process a request to change the name on a permit unless this box has been checked.

Requirements	Comments
3) Permit(s) to be rescinded	Complete this portion of the form only when you want to rescind an existing permit; otherwise, leave it blank.
4) Total volume of ethane proposed for removal	If you are applying for a new ethane removal permit, fill out the "Proposed volume authorized" line. The volume of ethane proposed for removal from Alberta must be expressed as the total volume in m^3 proposed for removal from Alberta over the entire term of the permit. This volume must not be expressed as a daily or annual volume. The maximum volume that may be removed under a short-term permit, including amendments, is 3 billion m^3. If an existing short-term ethane removal permit has authorized the removal of a volume of gas less than 3 billion m^3, the permit may be amended to increase the volume up to 3 billion m^3. However, if you have an existing short-term ethane removal permit authorizing the removal of 3 billion m^3 of gas and you have removed that volume of gas before the permit termination date, you may not amend the permit to take out additional volumes of ethane; the *GRPA* limits the volume allowed for removal under a short-term permit, including amendments to the permit, to 3 billion m^3. In this scenario, you must apply for a new permit. To request an amendment of an existing ethane removal permit, fill in both the "Existing volume authorized" and "Proposed volume authorized" lines.
5) Term of permit	The maximum term for a short-term ethane removal permit is two years (e.g., from November 1, 2006, to October 31, 2008). If you are applying for a new permit, fill out the line for "Proposed term and commencement date." For example, you may request a two-year term commencing November 1, 2006. Leave the "Existing term and commencement date" line blank. The term of an existing permit may be rolled

Requirements	Comments
	by an amendment to the permit to allow a further maximum term of two years, but only if the volume of ethane removed under the permit and all amendments does not exceed 3 billion m^3. If you want to amend a permit to roll the term, fill in both the "Existing term and commencement date" and the "Proposed term and commencement date" lines. A permit or an amendment to a permit may be made effective on the date it is issued or at some future date. However, the ERCB has no legislative authority to backdate a permit or an amendment to a permit.
6) Name of proposed market(s), and location and type of end-use customer to be served under the permit	The name of the proposed market is the company to which the ethane would initially be sold, as well as the names of any other companies that would acquire the ethane prior to its final sale to the end-use customer. The location of the end-use customer is province(s) in Canada and/or or state(s) in the United States.
7) Are transportation arrangements in place for transporting the applied-for gas from the Alberta receipt point(s) to the intended end-use customer?	If all transportation arrangements are in place, check the Yes box, and proceed to the next item on the form. However, if some or all of the transportation arrangements are not in place, check the No box, and explain what arrangements you have made and when you anticipate that any new facilities required would be completed. Name the pipelines ultimately leading to the end-use market, and state what has been done to ensure that transportation arrangements will be in place. While transportation arrangements do not have to be complete in order to obtain a long-term gas removal application, steps should have been taken to acquire them.
8) List the name and location (Legal Subdivision-Section-Township-Range, Meridian) of the facilities from which the ethane will be obtained	This includes gas processing and straddle plants.

Unit 7 Application for Special Well Spacing

7.1 Introduction

Well spacing defines the number of subsurface drainage locations necessary to maximize oil or gas recovery from a specific pool or formation. The objectives of spacing regulations are to promote conservation through efficient and orderly development of reservoirs and to protect the equity of mineral rights owners.

In accordance with Section 16(1) of the *Oil and Gas Conservation Act* (*OGCA*), a working interest participant that is entitled to the right to produce may apply for special well spacing. An applicant may apply for special well spacing to allow for more flexibility when locating wells and/or to increase the well density in a drilling spacing unit (DSU) for one or more of the following reasons:

- there will be improved recovery,
- additional wells are necessary to provide capacity to drain the pool at a reasonable rate that will not adversely affect the recovery from the pool,
- the pool spacing has already been established and the proposed spacing provisions are equal or more restrictive,
- increased deliverability is desirable in a gas field (for example, for the acceleration of the resource development due to urban encroachment), or
- the local geologic or topographical conditions may make it impractical to develop an area by drilling to prescribed target areas.

Any application for special well spacing must be made in accordance with *Directive 065* and must be supported with proper engineering arguments and associated production, geological, and other engineering data.

Well spacing applications approved by the ERCB are displayed on the Well Spacing Map. The disposition documents for all spacing applications can be viewed for 30 days after they have been issued using the IAR Query. Both the Well Spacing Map and the IAR Query can be accessed through Quick Links or the DDS system on the ERCB Web site www.ercb.ca.

7.2 Background

7.2.1 Standard DSUs and Target Areas

The ERCB has authority under the *OGCA* to designate DSUs and target areas and to make or amend regulations pertaining to them.

As described in Part 4 of the *Oil and Gas Conservation Regulations* (*OGCR*), the standard DSU is one section for a gas well and one quarter section for an oil well. The baseline well density is limited to one well per pool per DSU except for certain formations in areas identified in Schedule 13A and 13B of the *OGCR*, as shown in Figures 7.1 and 7.2.

Baseline well densities for the area identified in Schedule 13A are

- gas – 2 wells per pool per section in the Mannville Group, 4 wells per pool per section for the formations above the Mannville Group, and
- oil – 2 wells per pool per quarter section in the Mannville Group.

Baseline well densities for the area identified in Schedule 13B are

- gas – 4 wells per pool per section for the designated strata and stratigraphic equivalents between the top of the Smoky Group and the base of the Rock Creek Member.

Note that only the baseline well densities in the outlined areas of Schedule 13A and 13B were increased. The standard DSU size remains the same.

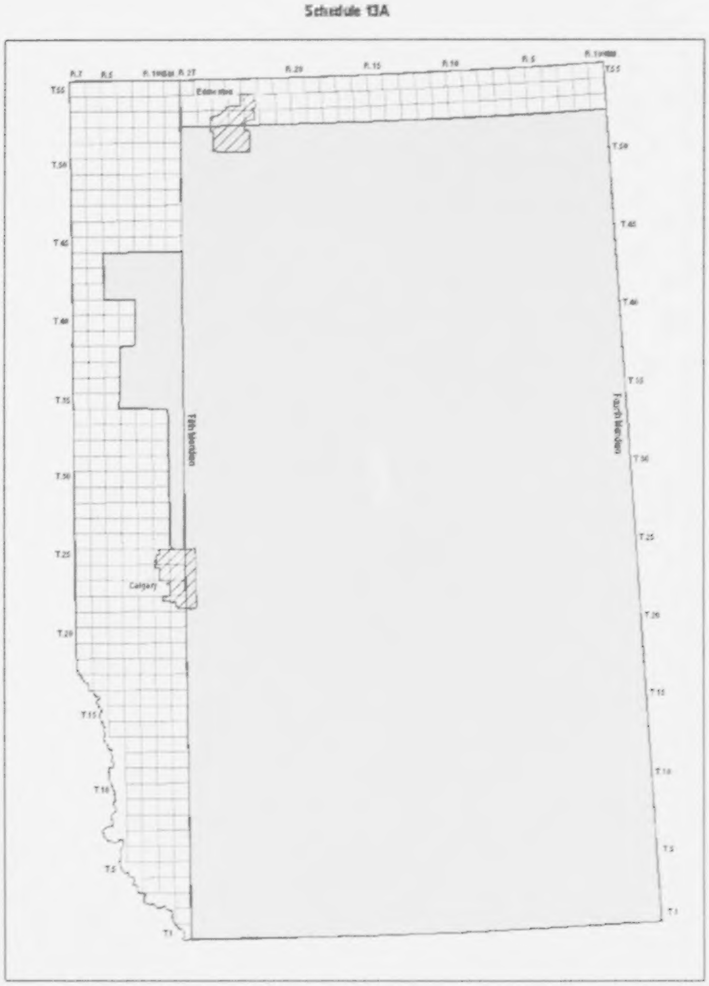

Schedule 13A
R.7
R.5
R.27
R.20
R.15
R.10
R.5
T.55
T.50
T.45
T.40
T.35
T.30
T.25
T.20
T.15
T.10
T.5
T.1
Edmonton
Calgary
Fifth Meridian
Fourth Meridian

Figure 7.1. *OGCR* Schedule 13A

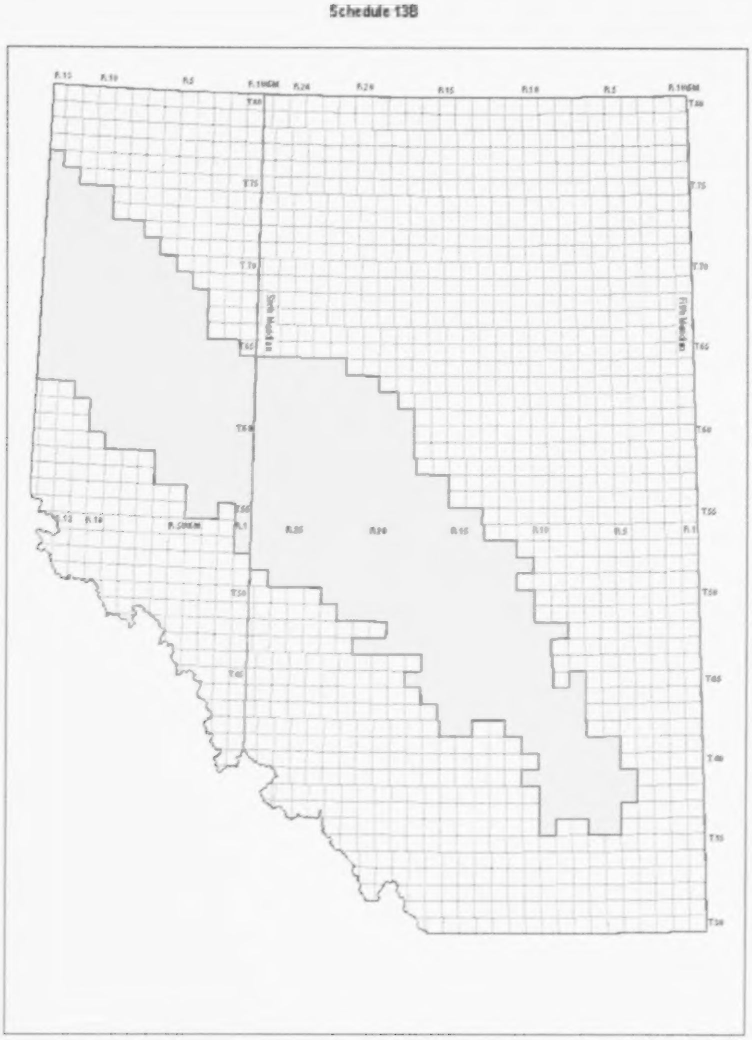

Schedule 13B
R.15
R.10
R.5
R.1W6M
R.24
R.20
R.15
R.10
R.5
R.1W6M
T80
T75
T70
T65
T60
T55
T50
T45
T40
T35
T30
Sixth Meridian
Fifth Meridian
R.15
R.10
R.5W6M
R.1
R.25
R.20
R.15
R.10
R.5
R.1

Figure 7.2. *OGCR* Schedule 13B

Target area locations for formations are dependent on the areas outlined in Schedules 13, 13A and 13B of the *OGCR*.

For a well producing from certain formations within the area shown in Schedule 13A, the target area is

- at least 200 metres (m) from the south and east boundaries of the quarter section for an oil well producing from the Mannville Group, and
- at least 300 m from the south and west boundaries of the section for a gas well producing to the base of the Mannville Group.

For a well producing from certain formations within the area shown in Schedule 13B, the target area is

- at least 200 m from all boundaries of the section for a gas well.

For a well producing from formations that are not included in Schedule 13A or 13B and are in Area 1 of Schedule 13, the target areas are

- at least 300 m from all boundaries of the section for a gas well, and
- at least 200 m from all boundaries of the quarter section for an oil well.

For a well producing from formations that are not included in Schedule 13A or 13B and are in Area 2 of Schedule 13, the target areas are

- at least 300 m from all boundaries of the section for a gas well, and
- LSD 6, 8, 14, or 16 of the quarter section for an oil well.

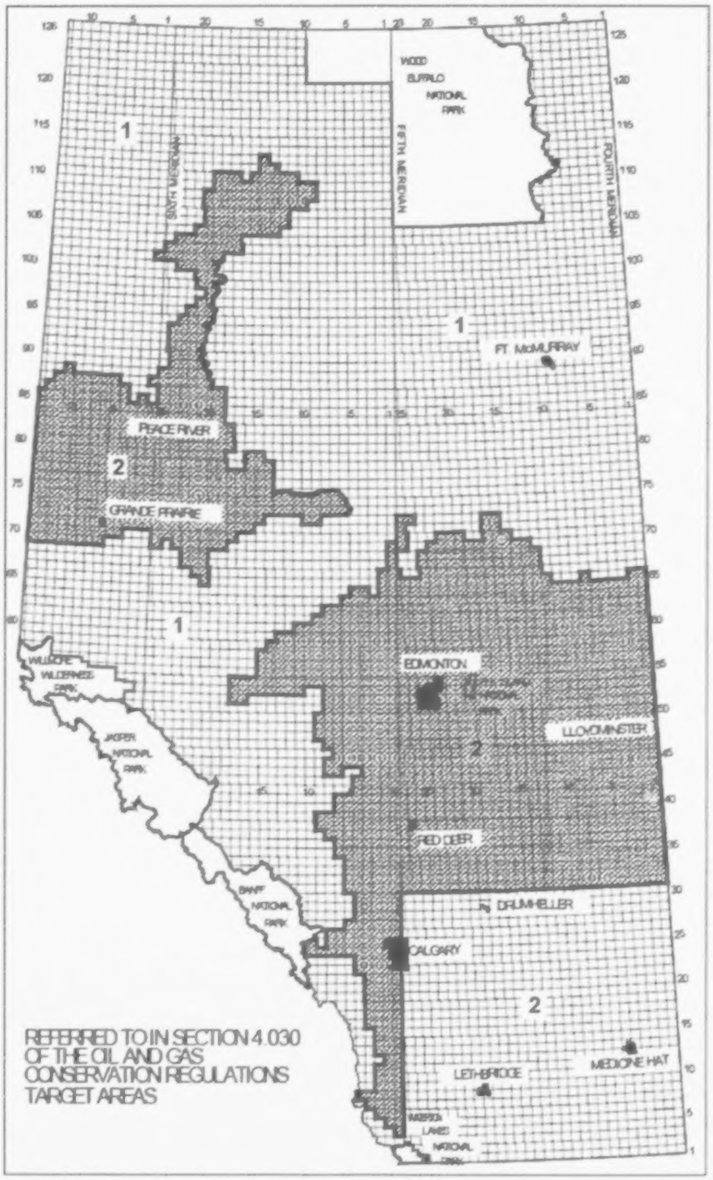

WOOD BUFFALO NATIONAL PARK
SIXTH MERIDIAN
FIFTH MERIDIAN
FOURTH MERIDIAN
1
FT. McMURRAY
PEACE RIVER
2
GRANDE PRAIRIE
1
WILLMORE WILDERNESS PARK
JASPER NATIONAL PARK
EDMONTON
ELK ISLAND NATIONAL PARK
LLOYDMINSTER
2
RED DEER
BANFF NATIONAL PARK
DRUMHELLER
CALGARY
2
LETHBRIDGE
MEDICINE HAT
WATERTON LAKES NATIONAL PARK
REFERRED TO IN SECTION 4.030
OF THE OIL AND GAS
CONSERVATION REGULATIONS
TARGET AREAS

Figure 7.3. *OGCR* Schedule 13

Note that any approved special well spacing supersedes Part 4 of the *OGCR*. .

7.2.2 Standard Buffer Zones for Holdings

The ERCB believes that the consistent application of standard buffer zones in a region greatly enhances equity, supports orderly and efficient development, and maximizes resource conservation. Standard buffer zones for holdings are consistent with the central target area concept used in Area 1 and with the corner target area concept used in Area 2 of the province.

The standard buffers for holdings with proposed well densities up to 4 wells per pool per standard DSU are noted below and are illustrated in detail in Appendix L.

Area	Holding or unit	Well density	Standard buffer
1	Gas	up to 4 wells/section/pool	200 m around all boundaries of a holding or unit
2	Gas	up to 4 wells/section/pool	300 m on south and west boundaries of a holding or unit
1	Oil	up to 4 wells/quarter section/pool	100 m around all boundaries of a holding or unit
2	Oil	up to 4 wells/quarter section/pool	200 m on south and east boundaries of a holding or unit

Note that for the designated strata and stratigraphic equivalents between the top of the Smoky Group and the base of the Rock Creek Member within the area identified in Schedule 13B, the standard buffer zone is 200 m around all boundaries of a holding.

7.2.3 Common Ownership

As defined by Section 1.020(2)(4) of the *OGCR*, holdings require common ownership at both the lessor and lessee levels in the area of the holding. Common ownership must be maintained to ensure the validity and preserve the equity within a holding. A farm-in or farm-out agreement has the potential to change the ownership so that it is no longer common throughout the area of a holding.

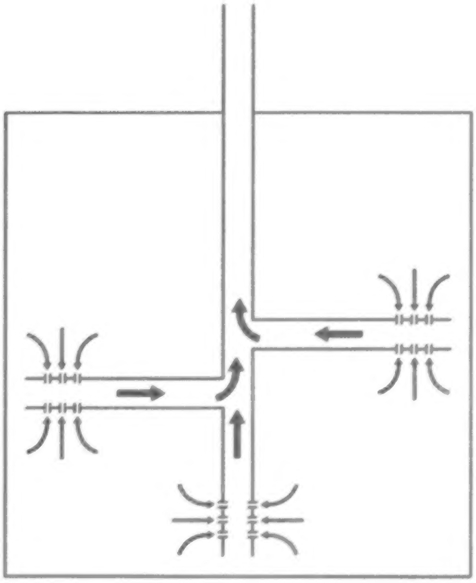
If the ownership within a holding is uncommon but all owners (both lessors and lessees) have agreed to work within the terms of the current holding, the ownership is considered to be common for the purposes of a holding. Such agreements are handled by the mineral owners and are dealt with outside of ERCB procedures. Mineral owners are responsible for managing these agreements to mitigate any potential risk of noncompliance.

7.2.4 Spacing and Horizontal/Multilateral Wells

The productive part of a horizontal wellbore in each DSU is considered a wellbore for the purpose of Section 5.005(1) of the *OGCR*. The productive part of a wellbore is the portion open to the producing zone or formation/pool. Each leg of a multilateral horizontal well counts as a wellbore, as shown in Figure 7.3.

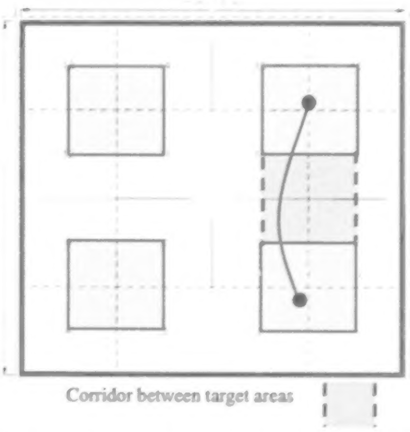
If any productive portion of the horizontal wellbore is off target, the entire horizontal well is considered off target and a penalty may be applied to the well's total production. If an operator can demonstrate that the off-target portion of a horizontal wellbore is no longer productive (i.e., has been plugged or isolated from the producing horizon), the wellbore would be considered as on target.

A horizontal well may be drilled across adjacent DSUs that have common mineral rights ownership at both the lessor and lessee levels or if a pooling agreement between the lessee(s) and lessor(s) is in place, as shown in Figure 7.4. In such cases, a spacing application is not required as long as the well density does not exceed what is currently approved. However, areas where horizontal development is being considered would most often require the establishment of holdings to accommodate the flexibility necessary for such a development.



The example in Figure 7.4 shows two lateral legs and one vertical leg. Assuming that all legs are producing from the same pool, this DSU would have three producing wells.

Figure 7.4. Example of producing horizontal/multilateral legs from a single DSU



If a horizontal well is drilled from target area to target area between DSUs of identical size, target area configuration, and mineral rights ownership, the corridor between target areas is deemed "on target." However, if any productive portion of the horizontal wellbore falls outside this corridor, the entire horizontal wellbore is considered off target and a penalty may be applied to the well's total production. Assuming that the horizontal well in this example is producing from the same pool in each quarter-section DSU, the well count would be one well per DSU.

Figure 7.5. Example of a horizontal oil well drilled in Area 1 (Central Target Area) across adjacent quarter-section DSUs of common mineral rights ownership

7.2.5 When to File a Spacing Application

An operator wishing to develop using DSUs, target areas, or well densities that deviate from the standards prescribed in Part 4 of the *OGCR* must apply to the ERCB and obtain approval for the special spacing prior to commencing production. Applications for special well spacing must contain information that fully and clearly supports the proposed change in spacing. In this regard, some level of development and collection and analysis of reservoir and production information is required to avoid the filing of premature and unsupported spacing applications.

7.2.6 How to Make a Spacing Application

A spacing application must be filed electronically using the Electronic Application Submission (EAS) system via the Digital Data Submission (DDS) system on the ERCB Web site www.ercb.ca. The ERCB will **not** accept paper applications. The application must be made using the appropriate Spacing Application form (see Appendix I), which is interactive with the Well Spacing Map. This form, in addition to Resources Applications Schedule 1 and the required attachments, must be included in the application. A well spacing application filed with the ERCB is displayed on the Well Spacing Map following registration.

The ERCB validates all applications to ensure that the application requirements have been met. Incomplete applications or those containing numerous or significant errors will be **closed**.

7.2.7 Types of Spacing Applications

7.2.7.1 Holding Application

Common mineral rights ownership at both the lessor and lessee level is a prerequisite to establish a holding (also see Section 7.2.7.6: Change in Approval Holder). A holding area must consist of at least one DSU or whole, contiguous DSUs of common mineral ownership.

A holding application is made pursuant to Section 5.190 of the *OGCR*, which allows for the establishment of a holding, and Section 79(4) of the *OGCA* to suspend the DSU and target area provisions for the holding area(s). The suspension of DSU and target area provisions affords the greatest flexibility to locate wells, access seismic features outside standard target areas, accommodate horizontal drilling, increase well density, and avoid surface obstructions or improvements, such as buildings, lakes, or rivers.

A request to suspend DSUs and target areas within a holding must include a proposed well density and a buffer zone distance between a well and the boundary of the holding area. A minimum interwell distance between wells within the holding area is not a mandatory provision but may also be considered.

If a unit has been established, a holding may also be applied for.

7.2.7.2 Fractional Tract of Land Application

A well cannot produce from a fractional tract of land until the tract of land has been approved as a DSU.

In accordance with Section 4.050(1) of the *OGCR*, an applicant must apply for approval to declare the fractional tract as a DSU if the fractional tract of land differs in size by more than 5 per cent from a standard DSU.

If the tract of land is at least half the size of a standard DSU prescribed for the area, the tract may be applied for as a standalone DSU.

A tract that is too small to be a standalone DSU may be joined with an adjacent DSU only if common ownership exists between the two. The adjacent DSU must be an entire DSU and located to the east or west of the fractional tract of land.

The typical target area for a fractional DSU, whether it is being proposed as a standalone DSU or is to be added to an adjacent DSU, is 300 m from and parallel to the sides of the DSU.

7.2.7.3 Reduced DSU Application

The use of holdings provides for the maximum flexibility to support development plans. Within a holding, a larger area exists compared to prescribed target areas, which can reduce or even mitigate surface land conflicts while still striking a balance between conservation and equity. If a need for increased well density is identified, holding applications should be filed.

If an applicant applies to reduce the size of a DSU under Section 4.040(3) of the *OGCR*, the application must be made on behalf of all mineral owners within the existing DSU. Divided mineral ownership within a DSU is not a reason to file a Reduced DSU application. If the mineral owners are unable to voluntarily negotiate a pooling arrangement, a Compulsory Pooling application may be filed with the ERCB.

An application requesting a reduction of the DSU within the Southeast Alberta Regional Spacing Area that mirrors the well density specified in the regulations is not necessary and will be closed.

Standard target areas must be requested for a Reduced DSU application. The use of a nonstandard target area must be filed as a Change in Target Area application.

7.2.7.4 Change in Target Area Application

The "first well" in the pool policy has removed the need to apply for a change in target area. If a well is not a "first well" candidate but requires flexibility in terms of location on the surface or access to a geological feature, it is recommended that an application for a holding be filed.

Under Section 4.040(1) of the *OGCR*, an applicant may apply to change the target area of a DSU, provided the change does not have an adverse impact on the equity of offset mineral owners. Written consent is required from all offset mineral owners who are being encroached upon by the proposed target area.

7.2.7.5 Rescinding a Holding

Under Section 5.220(b) of the *OGCR*, an applicant may apply to rescind all or part of an existing approved holding. A request to rescind a holding must be made using the Rescind form. Rescinding all or a portion of a holding may be necessary if common ownership no longer exists (also see Section 7.2.3). A common example of such a situation is when a lease for a DSU within a holding boundary has expired and reverted back to the Crown. All of an existing approved holding may also be rescinded if the standard spacing prescribed in Part 4 of the *OGCR* is sufficient.

Applications to remove a DSU(s) from a holding may only be filed for areas where the applicant has a working interest and wishes to rescind all or a portion of the holding in favor of the standard spacing specified in Part 4 of the *OGCR* or where a lease has expired and reverted back to the Crown.

There are no notification requirements for an application to rescind a holding.

Note that failure to realign holding boundaries to reflect common ownership is a High Risk noncompliance event (see *Directive 019: ERCB Compliance Assurance—Enforcement*).

7.2.7.6 Change in Approval Holder

Ownership within a holding is defined and explained in detail in Section 7.2.3. A Change in Approval Holder application must be filed when mineral ownership within an approved holding boundary is no longer common, and the boundaries of the holding need to be revised to reflect the new area of common ownership.

Where common ownership exists in an approved holding but the approval holder does not reflect the current company name, a Change in Approval Holder application may also be filed to update the approval holder of a holding.

There are no notification requirements for an application to change the approval holder of a holding.

Note that a Change in Approval holder is a spacing application type and must not be filed using a Transfer of Approval form.

7.3 Application Requirements and Expectations

7.3.1 Minimum Notification Requirements

Well spacing applications that have not met all applicable notification requirements will be closed and removed from the ERCB's agenda. Applications to rescind or change the approval holder for previously approved holdings have no notification requirements.

Refer to the Notification Guidelines section of *Directive 065: Resources Applications for Conventional Oil and Gas Reservoirs* for a detailed discussion on the objective, purpose, and guidelines of the notification process.

7.3.1.1 Preapplication Notification

Applicants must conduct preapplication notification. A minimum 15-business-day response period from the date the notification letter is mailed is required. An application filed with the ERCB before this notification period has expired will be closed.

7.3.1.2 How to Notify

Applicants must use applicable notification template letters (see Appendix J: Spacing Notification Templates) and must provide an accurate description of the entire area of application, proposed formation(s)/pools(s), and requested provisions, including requests for well exemptions from any requested provisions.

7.3.1.3 Whom to Notify

At a minimum, applicants must notify the following:

- All mineral lessees of oil, gas, and coal within the applied-for formation(s)/pool(s) in the application area and one standard DSU surrounding the application area. Notification must be conducted using the Lessees and Unleased Freehold Notification Letter Template in Appendix J.
- Any leased Freehold mineral owners of oil, gas, and coal within the applied-for formation(s)/pool(s) in the application area and one standard DSU surrounding the application area. (This notification is for informational purposes only to support ongoing dialogue between the lessee and the Freehold mineral rights owner.) Notification must be conducted using the Leased Freehold Notification Letter Template in Appendix J.
- Any Freehold mineral owners of oil, gas, and coal where mineral rights in the applied-for formation(s)/pool(s) are unleased in one standard DSU surrounding the application area. Notification must be conducted using the Lessees and Unleased Freehold Notification Letter Template in Appendix J.
- Alberta Energy (the Crown) for applications to reduce the size of a DSU and/or to establish a fractional tract of land as a DSU. This applies to mineral rights in the applied-for formation(s)/pool(s) that are both leased and unleased within the application area and one standard DSU surrounding the application area. Notification must be conducted using the Crown Lessor Notification Letter Template in Appendix J.

If any of the above applicable parties are not notified, the applicant must provide an explanation in the Reason for Incomplete Notification attachment.

7.3.1.4 Evidence of Notification

Applicants must provide evidence of notification to the ERCB as follows:

- A sample of each applicable letter used for notification about the proposed application. Do not provide copies all notification letters sent, but they must be made available upon request.
- A list of the mineral owners notified (do not provide names of individual Freehold mineral owners in this list. See the Mineral Rights Ownership and Notification List example in Appendix K: Special Well Spacing Attachment Examples). The percentage of working interests must be specified for mineral owners within the area of application.

7.3.1.5 Outstanding Objections

All outstanding objections, written and verbal, must be included in the application filed with the ERCB. In the case of a Freehold individual, the objection and any related material filed must not contain confidential or sensitive personal information (e.g., medical history, financial or family issues) unless the individual the information is about has consented to it being provided to the ERCB for filing on the public record. If the individual does not provide consent, applicants should discuss with ERCB staff what information should be included with the application to reflect the concerns of those individuals. In collecting personal information and providing it to the ERCB, applicants must also comply with all personal information protection legislation to which they are subject.

The application must include a discussion of how the applicant has addressed the unresolved concerns and its view of how the ERCB should proceed with the application. In accordance with *Directive 019* and the ERCB Risk Assessed Noncompliances list (available on the ERCB Web site www.ercb.ca under Industry Zone : Compliance and Enforcement : Risk Assessed Noncompliance), failure to attempt to resolve concerns or to notify the ERCB of outstanding issues is a High Risk noncompliance event.

7.3.2 Minimum Equity and Conservation Requirements

An application for special well spacing must include the following:

- A detailed discussion on how the proposed spacing will affect hydrocarbon recovery.
- A detailed discussion on how the well information provided in the Well Productivity and Volumetric Reserves Form supports the proposed spacing (see Section 7.6.3).
- Maps showing the lessors and lessees in the applied-for formation(s) only within the application area and one DSU surrounding the application area. The area of application must be outlined and the maps must be sufficiently scaled to provide a clear view of mineral rights ownership (see Appendix K). For areas with complex ownership, a map coded to a list of mineral rights owners may be used. Do not send title search documents in place of or in support of lessor and lessee maps.

When filing a holding application, a statement citing on what basis the ownership is common (see Section 7.2.3: Common Ownership).

If the application is for heavy oil, a fluid analysis specifying the oil density of the native reservoir fluid.

Any additional information to fully support the well spacing application should be included, such as

- pressure information,
- geological discussion,
- geological cross-sections,
- topographical mapping,
- net pay isopach mapping, and
- development plans (specific locations and timing to drill; type of drilling—pad, horizontal, vertical).

All data entered in the application must be presented in International System of Units (SI). Applications containing information not in SI units will be closed.

7.3.3 Production Information and Volumetric Reserves Requirements

7.3.3.1 Commingled Production

The minimum regulatory requirements for well testing within a development entity (DE) do not provide for production information necessary to properly assess the optimum spacing for a specific pool or formation. When commingling production in an area where increased well densities are ultimately needed, collection of appropriate production and reservoir data is required to support changes in well spacing.

When applying for special well spacing in areas where commingled production has been approved or is occurring within a DE, an applicant must provide production information for each formation/pool being applied for. Segregated production data are best, but where formation-specific production information is not available, other sources or means of determining production information may be used (e.g., allocation of production contributions derived from spinner log surveys; production from nearby control wells).

The applicant must ensure that the correct well spacing is in place for all producing formations/pools within a DSU where commingled production is occurring.

7.3.3.2 Production Information Requirements

Production information for each applied-for formation or pool is required for applications proposing a change in well spacing. Selected wells must represent the typical performance in and/or surrounding the application area and have production from the formation, substance (i.e., oil or gas), and production source (i.e., sands or coals) being applied for. The application must include a discussion of the production data provided and how the data support the proposed spacing change.

All production information supplied in support of an application must be provided using the EAS Production Form. The Production Form allows for auto-population of ERCB production data upon entering a well licence number and selecting the appropriate Unique Well Identifier (UWI) applicable to the application. ERCB production data should be revised in the Applicant Data section of the form if the auto-populated data are not current or correct; in the case of a commingled well, the producing formation must be entered and production data for each applied-for formation are required. Any changes to ERCB data must be addressed and explained in the "Reason for Production Form Edits" attachment. If providing production information for a formation based on allocation, the methodology used to determine the allocation for each applied-for formation in the wellbore must be included. Refer to Section 7.6.3 for further details on required production information.

Production information is not required for applications to rescind holdings, establish a fractional tract of land as a DSU, or when changing the approval holder of a holding.

7.3.4 Reserves Information Requirements

Based on the technical complexity of an application, the ERCB may require reserves information and performance data to support a change in well spacing. Where required, applicants must provide reserves data and recoverable reserves estimates from wells representative of the application area. The application must include a discussion of the reserves information provided and detail how the data support the proposed spacing change.

All reserves information provided in support of an application must be provided using the EAS Volumetric Reserves Form. All production plots and decline analysis for wells where volumetric reserves data have been provided must be included in the "Production Decline Plot and Analysis" attachment.

Refer to Section 7.6.3 for further details for volumetric reserves information.

7.4 How the ERCB Processes the Application

The ERCB processes special well spacing applications along three risk-based processing paths: quick, standard, and nonstandard, having regard for

- location of the proposed application area(s) relative to previously approved spacing for the same formation(s) and substance,
- proposed provisions, and
- available production and reservoir information.

The processing path may change if the ERCB finds that additional information is required to technically support the application.

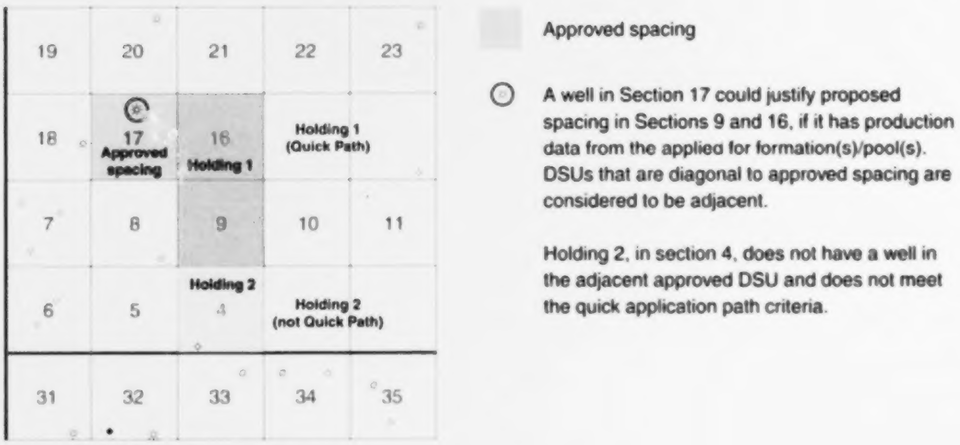
The minimum requirements for an application that meets the quick application path criteria are significantly fewer than those for a standard and nonstandard path application. Therefore, it is beneficial to analyze development plans before preparing and submitting a special well spacing application.

7.4.1 Quick Application Path

Well spacing applications that meet **all** the baseline criteria outlined below and clearly meet all *Directive 065* requirements qualify to be processed in an expedited manner using a quick application path. The review emphasis for quick path applications shifts from the reservoir's behaviour in the application area to behaviour in the adjacent previously approved and developed DSU.

Minimum Baseline Criteria for the Quick Application Processing Path

1) Each applied-for holding within the application area must be adjacent to an existing approval. See Figure 7.6.
2) The adjacent DSU must have a well with proven production information from all applied-for formation(s)/pool(s).
3) The applied-for well density must be less than or equal to the approved well density.
4) Proposed well densities must be no more than 2 wells per pool per quarter section for oil and 4 wells per pool per section for gas.



▨ Approved spacing

○ A well in Section 17 could justify proposed spacing in Sections 9 and 16, if it has production data from the applied for formation(s)/pool(s). DSUs that are diagonal to approved spacing are considered to be adjacent.

Holding 2, in section 4, does not have a well in the adjacent approved DSU and does not meet the quick application path criteria.

Figure 7.6. Quick application path

5) Standard buffer zones must be proposed.

Note that the same baseline criteria apply to quick path reduced DSU applications.

7.4.2 Standard Application Path

If the application does not meet the quick application path criteria, it must meet **all** the following minimum baseline criteria to be processed on the standard application path:

Minimum Baseline Criteria for the Standard Application Processing Path

1) Any part of a holding must be within 3 standard DSUs of an existing approval. See Figure 7.7.
2) There must be proven production information from a minimum of one well in the applied-for formation(s)/pool(s) in each proposed holding/unit.
3) The applied-for well density must be less than or equal to the approved well density.
4) Proposed well densities must be no more than 2 wells per pool per quarter section for oil and 4 wells per pool per section for gas.
5) Standard buffer zones must be proposed.

Wells submitted in the application must have enough production history to allow for the submission of volumetric reserves data that can clearly support the need for the requested special well spacing. Additional production and volumetric reserves information from producing wells in surrounding areas should also be included to fully support an application.

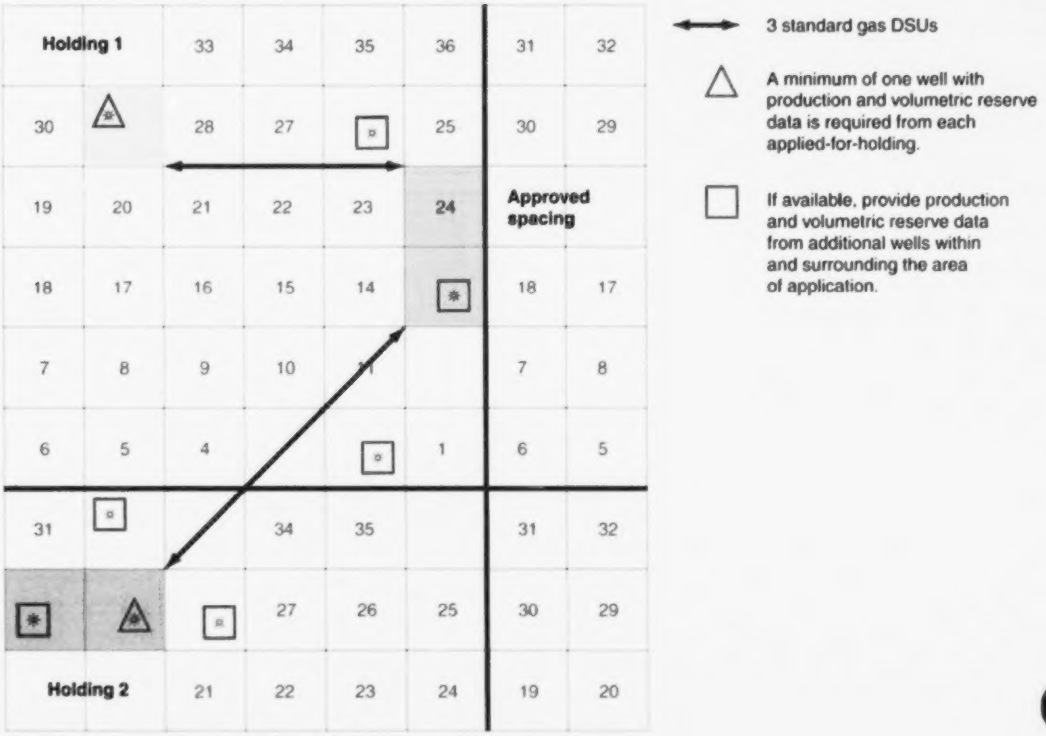

Holding 1
33
34
35
36
31
32
30
28
27
25
30
29
19
20
21
22
23
24
Approved spacing
18
17
16
15
14
18
17
7
8
9
10
11
7
8
6
5
4
1
6
5
31
34
35
31
32
27
26
25
30
29
Holding 2
21
22
23
24
19
20
3 standard gas DSUs
A minimum of one well with production and volumetric reserve data is required from each applied-for-holding.
If available, provide production and volumetric reserve data from additional wells within and surrounding the area of application.

Figure 7.7. Standard application path

Note that the same baseline criteria apply to standard path special DSU applications.

7.4.3 Nonstandard Application Path

Applications not meeting the quick or standard application path criteria are processed on the nonstandard application path. Such applications typically propose complex or innovative spacing requiring more detailed analysis. Production and volumetric reserves data should be supplied from wells that have enough production history to allow for the submission of volumetric reserves data that can clearly support the need for the requested special well spacing. These wells can be within and/or surrounding the applied-for area.

In some cases the ERCB may find it necessary to gather more data to support the optimum spacing for a resource. In such cases, an application may be approved as a pilot area and the applicant is required to follow up with the ERCB to validate reservoir interpretation, assess performance predictions and, if necessary, manage unintended consequences.

7.4.4 Processing Paths for Different Spacing Application Types

The following table shows the possible processing paths used for the different types of well spacing applications.

Holding/unit	Reduced DSU	Fractional tract of land	Change in target area	Rescind holding
Quick	Quick			Quick
Standard	Standard	Standard		
Nonstandard	Nonstandard		Nonstandard	

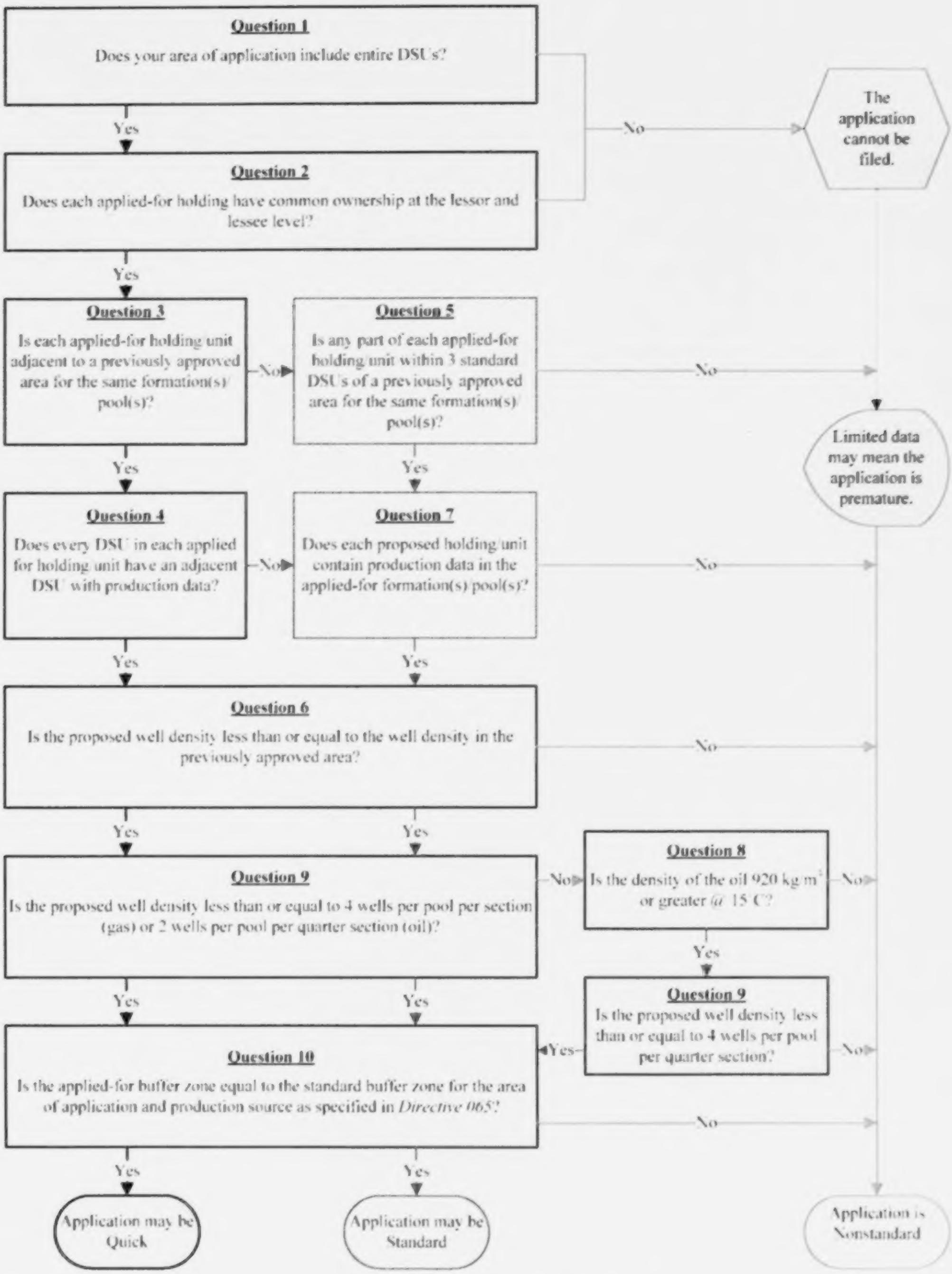
Note that upon review of the application, the ERCB may change the application processing path, resulting in an additional information request.

7.4.5 Applications with Outstanding Objections

Any application with an outstanding objection requires additional review, regardless of the processing path criteria met.

7.4.6 ERCB Spacing Application Decision Tree

Figure 7.8 outlines the ERCB decision process for holding applications. Applications for reduced DSUs mirror the holding standards for production information, well densities, and target areas.


Question 1
Does your area of application include entire DSUs?
Yes
No
The application cannot be filed.
Question 2
Does each applied-for holding have common ownership at the lessor and lessee level?
Yes
Question 3
Is each applied-for holding unit adjacent to a previously approved area for the same formation(s)/pool(s)?
No
Question 5
Is any part of each applied-for holding unit within 3 standard DSUs of a previously approved area for the same formation(s)/pool(s)?
No
Limited data may mean the application is premature.
Yes
Yes
Question 4
Does every DSU in each applied for holding unit have an adjacent DSU with production data?
No
Question 7
Does each proposed holding unit contain production data in the applied-for formation(s)/pool(s)?
No
Yes
Yes
Question 6
Is the proposed well density less than or equal to the well density in the previously approved area?
No
Yes
Yes
Question 9
Is the proposed well density less than or equal to 4 wells per pool per section (gas) or 2 wells per pool per quarter section (oil)?
No
Question 8
Is the density of the oil 920 kg/m3 or greater @ 15°C?
No
Yes
Question 9
Is the proposed well density less than or equal to 4 wells per pool per quarter section?
No
Yes
Yes
Yes
Question 10
Is the applied-for buffer zone equal to the standard buffer zone for the area of application and production source as specified in Directive 065?
No
Yes
Yes
Application may be Quick
Application may be Standard
Application is Nonstandard

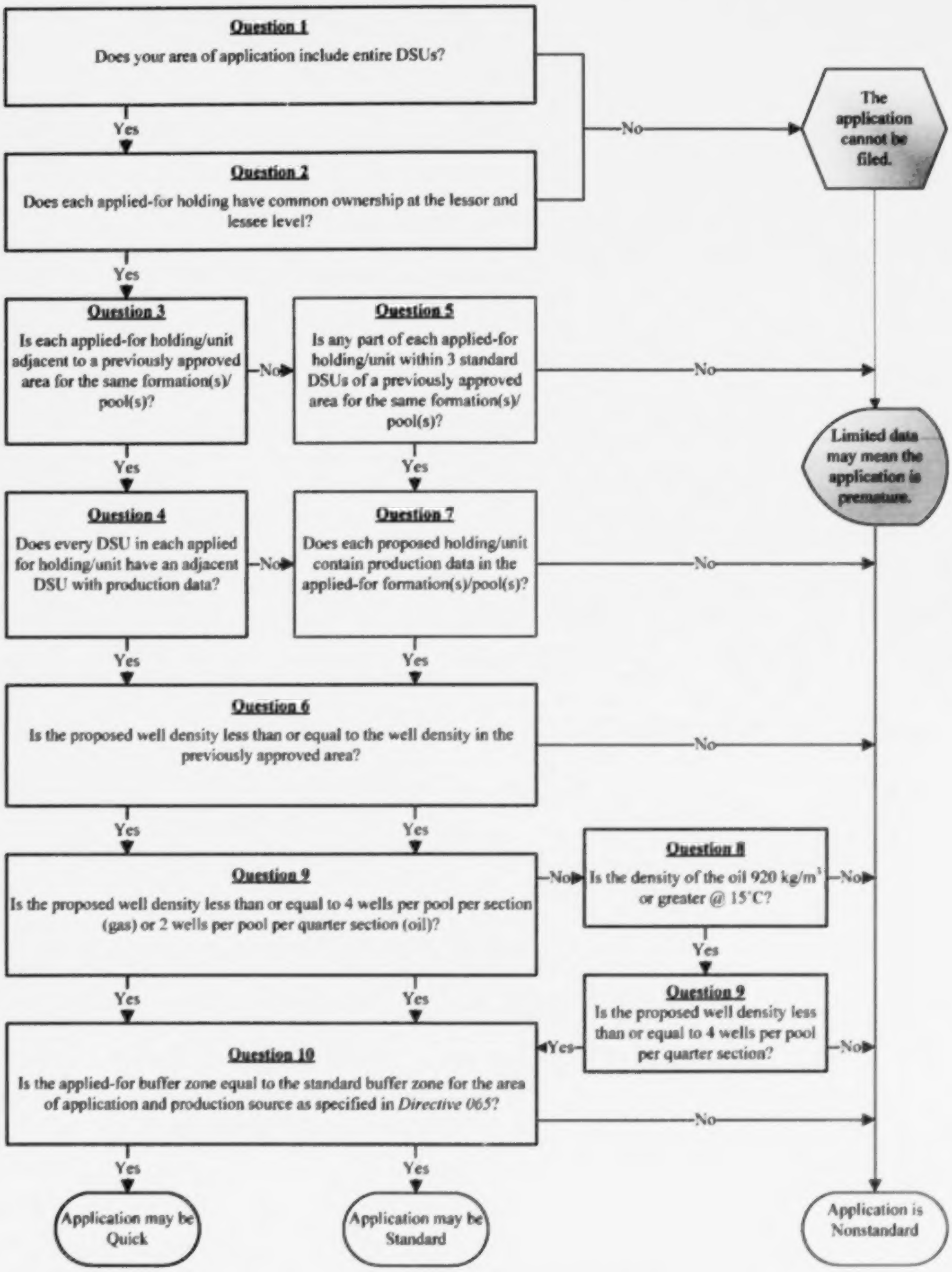
Standard buffering for oil

Area 1: 100 m on all boundaries of the holding(s).
Area 2: 200 m on the south and east boundaries of the holding(s).

Standard buffering for gas

Area 1: 200 m on all boundaries of the holding(s).
Area 2: 300 m on the south and west boundaries of the holding(s).

Figure 7.8. ERCB decision tree for holding/unit applications


Question 1
Does your area of application include entire DSUs?
Yes
No
The application cannot be filed.
Question 2
Does each applied-for holding have common ownership at the lessor and lessee level?
Yes
Question 3
Is each applied-for holding/unit adjacent to a previously approved area for the same formation(s)/ pool(s)?
No
Question 5
Is any part of each applied-for holding/unit within 3 standard DSUs of a previously approved area for the same formation(s)/ pool(s)?
No
Limited data may mean the application is premature.
Yes
Yes
Question 4
Does every DSU in each applied for holding/unit have an adjacent DSU with production data?
No
Question 7
Does each proposed holding/unit contain production data in the applied-for formation(s)/pool(s)?
No
Yes
Yes
Question 6
Is the proposed well density less than or equal to the well density in the previously approved area?
No
Yes
Yes
Question 9
Is the proposed well density less than or equal to 4 wells per pool per section (gas) or 2 wells per pool per quarter section (oil)?
No
Question 8
Is the density of the oil 920 kg/m³ or greater @ 15°C?
No
Yes
Question 9
Is the proposed well density less than or equal to 4 wells per pool per quarter section?
Yes
No
Yes
Yes
Question 10
Is the applied-for buffer zone equal to the standard buffer zone for the area of application and production source as specified in Directive 065?
No
Yes
Yes
Application may be Quick
Application may be Standard
Application is Nonstandard

Standard buffering for oil

Area 1: 100 m on all boundaries of the holding(s).
Area 2: 200 m on the south and east boundaries of the holding(s).

Standard buffering for gas

Area 1: 200 m on all boundaries of the holding(s).
Area 2: 300 m on the south and west boundaries of the holding(s).

Figure 7.8. ERCB decision tree for holding/unit applications

7.5 Attachments Required for a Special Well Spacing Application

The following is a list of common attachment types related to a spacing application. The EAS system will prompt for mandatory attachments, which depend on the type of spacing application being filed and on selections made on the spacing forms.

The content in each attachment must represent the attachment type and associated description or the application will be closed.

EAS attachment type	Description	Template
Application	Application requirements as per *Directive 065*.	
Lessor Map	Map showing the lessor(s) only in the applied-for formation(s)/pool(s) within the application area and one DSU surrounding the application area.	Lessor Map and Notification Area (Appendix K)
Lessee Map	Map showing the lessee(s) only in the applied-for formation(s)/pool(s) within the application area and one DSU surrounding the application area.	Lessee Map and Notification Area (Appendix K)
Freehold Notice Letter	A copy of the letter used to notify individual Freehold mineral rights owners of the application.	Leased Freehold Notification Letter (Appendix J) Lessees and Unleased Freehold Notification Letter (Appendix J)
Crown Notice Letter	A copy of the letter used to notify the Crown.	Crown Lessor Notification Letter (Appendix J)
Industry Notice Letter	A copy of the letter used to notify mineral owners of the application.	Lessees and Unleased Freehold Notification Letter (Appendix J)
Mineral Owner Notification List	List of mineral owners notified of the application.	Mineral Rights Ownership and Notification List (Appendix K)
Reason for Change In Target Area	Explanation of why a change in target area is required.	
Production Decline Plot and Analysis	Production decline plot(s) and analysis.	
Objection(s)/Concern(s)	Objection(s) or documentation of concern(s).	
Isopach Map	Net oil and/or gas pay map.	
Applicant Response to Objection	Written response by applicant to intervener.	
Material Balance Reserves	Material balance reserves, including existing and projected recovery factors, recoverable reserves, and data used to determine estimates.	
Miscellaneous	Miscellaneous attachments in support of the application.	
Fluid Analysis	An analysis of the native reservoir fluid, including the oil density.	
Pressure History	A tabulation of pressure history of the subject pool.	
Reason for Incomplete Notice	An explanation why *Directive 065* notification requirements were not met.	
Reason for Well Exemption	An explanation of why the well exemption is requested.	
Reason for Production Form Edits	An explanation of why changes were made to the ERCB production data.	

7.6 Explanatory Notes for Application Form Questions

The spacing application forms are in Appendix I. The numbering below correspond to the questions on the forms.

7.6.1 Schedule 1—Resources Applications

All spacing applications must include Schedule 1—Resources Applications. You must select as an application type either Spacing: Gas or Spacing: Oil. Once selected, an additional field of Application Purpose is enabled, and from the drop-down list you must select one of the following application purposes:

- New Spacing—to create an application for a new area of spacing or to amend areas and/or provisions of previously approved spacing.
- Rescind Spacing—to make an application to remove existing approved holdings and revert to the underlying DSUs and target areas.
- Change in Approval Holder—to create an application to change the name of the approval holder or to change holding boundaries to reflect current mineral ownership.

In Schedule 1, Sections 3: Locations, 4: Field and Pool List, and 5: Ownership and Notification Information, questions 2, 2a, and 3 are not required for well spacing applications.

7.6.2 Spacing Form

7.6.2.1 Notification Requirements

There are no notification requirements for applications to rescind or change approval holder.

1) Were Directive 065 *notification templates used?*

Select YES if notification to all parties was conducted using the appropriate notification templates (see Appendix J).

If you select NO, your application cannot be filed. *Directive 065* notification templates must be used.

Notification templates that have been extensively modified and no longer meet the intent of the notification letter as set out by the ERCB will be closed.

2) Have all parties been notified in accordance with Directive 065*?*

Select YES if all parties were contacted (see Section 2.1.3).

Select NO if this requirement has not been met but you are still choosing to file a spacing application. You must include a "Reason for Incomplete Notification" attachment with your application.

3) What was the mailing date of the last notification letter sent?

Enter the date the last notification letter was sent. A minimum 15-business-day response period from the date the notification letter is mailed is required before an application can be registered with the ERCB.

4) Are there any outstanding objections or concerns?

Select YES if there are unresolved concerns or objections from one or more parties.

Select NO if there are no known unresolved concerns about the application.

5) Is the application consistent with the details in the notification?

Select YES if the application area, formation(s)/pool(s), proposed provisions, and any well exemptions in the application are consistent with those stated in notification letters.

If you select NO, you must include an explanation in the application attachment. If the ERCB finds that the details of the application were not properly outlined in the notification letters, the application may be closed.

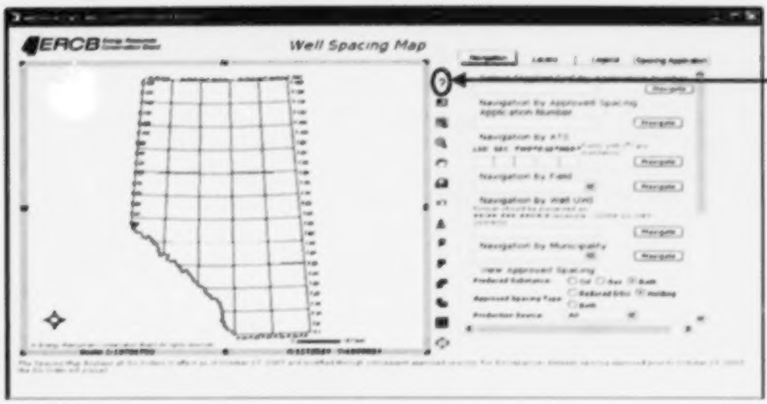
7.6.2.2 Application Type

Select one of the following:

Spacing application type	Description
Holding or unit	
Holding	Establish a holding comprising whole contiguous DSUs in accordance with Sections 5.190 and 5.200 of the *OGCR* and suspend the DSUs and target areas in the holding in accordance with Section 79(4) of the *OGCA*.
Unit	Suspend the DSUs and target area provisions within a unit or partial unit in accordance with Section 79(4) of the *OGCA*.
Special DSU	
Change in target area	Establish a target area that differs from the prescribed target area in accordance with Section 4.040(1) of the *OGCR*.
Reduced DSU	Reduce the size of the DSU in accordance with Section 4.040(3) of the *OGCR* from the normal DSU as prescribed in Part 4 of the *OGCR* or from that previously approved.
Fractional tract of land	Establish a fractional tract of land as a DSU in accordance with Section 4.050(1) of the *OGCR*.

7.6.2.3 Area of Application

To select your application area and applied-for formation(s) or pool(s), click View Map to open the Well Spacing Map window. For information on how to do this, see *Online Help Link*.



Online Help

7.6.2.4 Application Details

1) What is the source of production?

Select the production source, either sand or coal. Only one production source can be selected for each application. If application areas involve both production sources, you must file multiple applications and relate them on Schedule 1 in Section 6: Future Applications.

Should your application be for the production of shale gas, select a production source of sand. Specify in the Application attachment type that the proposed spacing is for the production of shale gas and meets the shale gas definition set out in *Bulletin 2009-23: Shale Gas Development—Definition of Shale and Identification of Geological Strata*.

2) As defined by Schedule 13 of the OGCR, *what area of the province is the application in?*

This field is populated based on the application area selected on the Well Spacing Map. Areas 1 and 2 are used to define the standard buffer zones (see Appendix L) and target areas (see Figure 7.3). The table below defines how Areas 1 and 2 are determined.

Area of application	Buffer zone/target area
All of the application area is in Area 1	Area 1
All of the application area is in Area 2	Area 2
Equal application areas in Area 1 and Area 2	Area 2
Unequal application areas in Area 1 and Area 2	Buffer zone/target area of largest application area

7.6.2.5 Holdings or Units

1) Does your area of application include entire DSUs?

Select YES if each area of application contains whole DSUs.

If you select NO, the application cannot be filed as the area of application must contain whole DSUs.

2) Does each applied-for holding have common ownership at the lessor and lessee levels?

Select YES if each applied-for holding has common mineral rights ownership at both the lessor and lessee levels as defined in Section 1.020(2)(4) of the *OGCR* or a voluntary agreement is in place that pools the lessor and lessee interests.

If you select NO, the application cannot be filed as common mineral rights ownership is a prerequisite to establish a holding (see Section 7.2.3).

This question is not applicable if the application subtype is "Unit."

3) Is each applied-for holding/unit adjacent to a previously approved area for the same formation(s)/pool(s)?

Select YES if each applied-for holding or unit in the application area is adjacent to a previously approved area for the same formation(s) or pool(s). Diagonal DSUs are considered to be adjacent.

Select NO if each applied-for holding or unit area is not adjacent to a previously approved area for the same formation(s)/pool(s).

4) Does every DSU in each applied-for holding/unit have an adjacent DSU with production data?

Select YES if every DSU in each applied-for holding or unit has an adjacent DSU with well production data for all applied-for formation(s) or pool(s) within the previously approved area. (See Figure 7.6: Quick Application Path.)

Select NO if every DSU in each applied-for holding or unit does not have an adjacent DSU with well production data for all applied-for formation(s)/pool(s).

5) Is any part of each applied-for holding/unit within 3 standard DSUs of a previously approved area for the same formation(s)/pool(s)?

Three standard DSUs is the distance from any boundary of the applied-for holding/unit to any boundary of a previously approved area. This includes diagonal DSUs. (See Figure 7.7: Standard Application Path.)

Select YES if any part of each applied-for holding/unit is within 3 standard DSUs of any boundary of a previously approved holding/unit or reduced DSU for the same formation(s) or pool(s).

Select NO if any holding within the area of application does not have a boundary that is within 3 standard DSUs of an approval for the same formation(s)/pool(s).

6) Is the proposed well density less than or equal to the well density in the previously approved area?

Select YES if the proposed well density is less than or equal to the well density in the previously approved area.

Select NO if the proposed well density is greater than the well density in the previously approved area.

7) Does each proposed holding/unit contain production data in the applied-for formation(s)/pool(s)?

Select YES if each holding or unit has at least one well with enough production history to allow for the submission of volumetric reserves data that can clearly support the need for the requested special well spacing in the applied-for formation(s) or pool(s). Additional production and volumetric reserves information from producing wells in surrounding areas should also be included to fully support an application.

Select NO if any proposed holding does not contain production data in the applied-for formation(s)/pool(s).

8) Is the density of the oil 920 kilograms per cubic metre (kg/m^3) or greater at 15°C?

Heavy oil, as defined in *Directive 017: Measurement Requirements for Upstream Oil and Gas Operations*, is "crude oil production with a density of 920 kg/m^3 or greater at 15°C." This crude oil density incorporates most of the areas of east-central Alberta, where heavy oil production operations normally occur. Heavy oil development typically requires higher well densities to maximize recovery.

Select YES if the application is for heavy oil. You must attach a Fluid Analysis that contains an analysis of the native reservoir fluid, which includes the density of the oil. If the proposed well density is >2 wells per pool per quarter but does not exceed 4 wells per pool per quarter section, the application will be registered in the nonstandard processing path. However, upon registration, it will be reviewed for the appropriate processing pathway and may qualify as a standard path application.

Select NO if the application is not for heavy oil.

9) Enter the proposed well density.

All holding/unit applications must propose a well density. Well density is defined as the number of wells per pool per area. Enter the well density and then select the well density area. Possible well density areas are

- 1 Legal Subdivision
- 2 Legal Subdivisions
- 1 Quarter Section
- 1 Half Section
- 1 Section

Note that typically well density areas are equivalent to the size of the standard DSU (e.g., if the standard DSU is 1 section, the well density area would typically be per pool per 1 section).

10) The standard buffer zone distance and orientation for this area of the province is:

This is populated based on the spacing application type (Spacing: Gas or Spacing: Oil) selected on Schedule 1 and the area of application selected on the Well Spacing Map.

The standard buffer zones within Areas 1 and 2 (Schedule 13 of the *OGCR*) of the province are as indicated in the table below.

Area	Holding or unit	Well density	Standard buffer zone
1	Gas	up to 4 wells/section/pool	200 m on all boundaries of a holding or unit
2	Gas	up to 4 wells/section/pool	300 m on south and west boundaries of a holding or unit
1	Oil	up to 4 wells/quarter section/pool	100 m on all boundaries of a holding or unit
2	Oil	up to 4 wells/quarter section/pool	200 m on south and east boundaries of a holding or unit

10a) Do you want to proceed with the standard buffer zone distance and orientation?

Select YES if you are proposing the standard buffer zone as shown in the table in question 10.

Select NO to request a nonstandard buffer zone. You must enter the buffer zone distance and orientation in questions 10b and 10c and provide additional technical information supporting the request.

10b) If NO, enter the buffer zone distance.

Enter the buffer zone distance from the boundaries of each holding/unit in metres.

10c) Enter the buffer orientation.

Select the boundaries of the holding/unit that the buffer zone distance applies to.

11) Are you requesting an interwell distance?

If you select YES, enter the requested interwell distance in question 11a.

Note that an interwell distance is not required for a holding/unit spacing application.

11a) If YES, enter the interwell distance.

7.6.2.6 Well Exemptions

Well exemptions are not applicable for applications for rescind or change in approval holder.

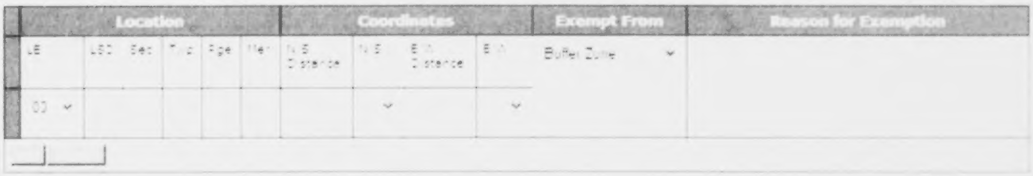
1) Are any well exemptions requested?

Select YES if you are requesting a well exemption.

If you select YES, the table below will be displayed.

- Enter the location of the proposed well exemption (XX/XX-XX-XXX-XXWX).
- Then enter the bottomhole coordinates and select a north or south direction from the drop-down menu.
- Then repeat this for the E/W distance and direction.
- The Exempt From column has two values: Buffer Zone and Interwell Distance. Select the one you are proposing the well to be exempt from.

- In the Reason for Exemption column, enter a short description of your reason for making the request. A detailed explanation of the well exemption request and additional supporting information can be included as a "Reason for Well Exemption" attachment.
- Once all the columns in the table have been populated, you must select the Add button to make the request a part of your application.



7.6.2.7 Special Drilling Spacing Units

1) Does your area of application include entire DSUs?

Select YES if the application area includes an entire DSU. Applications to reduce the size of a DSU must include an entire DSU.

If you select NO, the application cannot be filed.

2) Are you applying on behalf of all working interest owners within the area of application?

You must file the application on behalf of all working interest owners where mineral interests within the applied-for DSUs are divided. Select YES if you are applying on behalf of all divided working interest owners. Selecting YES indicates they all agree with the application.

If you select NO, the application cannot be filed. If all divided mineral interest owners within a DSU cannot reach a voluntary operating arrangement, you may submit a compulsory pooling application to force pool interests within the DSU.

3) Are you reducing the size of the current DSU?

Select YES if in addition to changing the target area, you are also requesting a reduction in size of the current DSU.

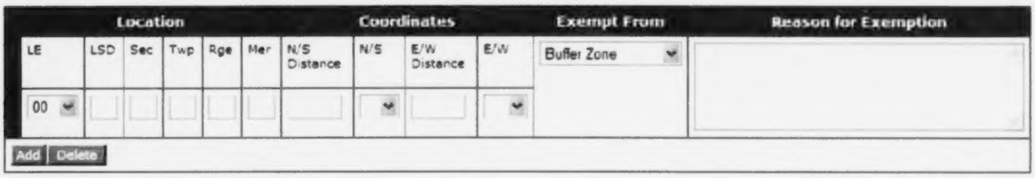
Select NO if you are requesting a change in the target area within the current DSU.

4) Is each applied-for contiguous area of application adjacent to a previously approved area for the same formation(s) pool(s)?

Select YES if each applied-for contiguous area of application is adjacent to a previously approved area for the same formation(s) or pool(s). Diagonal DSUs are considered to be adjacent.

Select NO if each applied-for contiguous area is not adjacent to a previously approved area for the same formation(s)/pool(s).

- In the Reason for Exemption column, enter a short description of your reason for making the request. A detailed explanation of the well exemption request and additional supporting information can be included as a "Reason for Well Exemption" attachment.
- Once all the columns in the table have been populated, you must select the Add button to make the request a part of your application.



Location							Coordinates			Exempt From	Reason for Exemption
LE	LSD	Sec	Twp	Rge	Mer	N/S Distance	N/S	E/W Distance	E/W	Buffer Zone	
00											

7.6.2.7 Special Drilling Spacing Units

1) Does your area of application include entire DSUs?

Select YES if the application area includes an entire DSU. Applications to reduce the size of a DSU must include an entire DSU.

If you select NO, the application cannot be filed.

2) Are you applying on behalf of all working interest owners within the area of application ?

You must file the application on behalf of all working interest owners where mineral interests within the applied-for DSUs are divided. Select YES if you are applying on behalf of all divided working interest owners. Selecting YES indicates they all agree with the application.

If you select NO, the application cannot be filed. If all divided mineral interest owners within a DSU cannot reach a voluntary operating arrangement, you may submit a compulsory pooling application to force pool interests within the DSU.

3) Are you reducing the size of the current DSU?

Select YES if in addition to changing the target area, you are also requesting a reduction in size of the current DSU.

Select NO if you are requesting a change in the target area within the current DSU.

4) Is each applied-for contiguous area of application adjacent to a previously approved area for the same formation(s)/pool(s)?

Select YES if each applied-for contiguous area of application is adjacent to a previously approved area for the same formation(s) or pool(s). Diagonal DSUs are considered to be adjacent.

Select NO if each applied-for contiguous area is not adjacent to a previously approved area for the same formation(s)/pool(s).

5) Does every DSU in each applied-for contiguous area of application have an adjacent DSU with production data?

Select YES if every DSU in each applied-for contiguous area of application has production data from the applied-for formation(s)/pool(s) in the adjacent DSU, which is equal in size to the existing DSU in the area of application. Diagonal DSUs are considered to be adjacent (see Figure 7.6).

If the well has insufficient production data, you must provide production information from other wells in the area.

Select NO if each applied-for contiguous area of application does not have an adjacent DSU with production data.

6) Is any part of each contiguous area of application within 3 standard DSUs of a previous approval in the applied-for formation(s)/pool(s)?

Three standard DSUs is the distance from any boundary of a contiguous (sharing a common boundary) application area to any boundary of a previous approval area.

Select YES if any part of each contiguous area of application is within 3 standard DSUs of any boundary of a previously approved area. See Figure 7.7.

Select NO if any contiguous area of application does not have a boundary within 3 standard DSUs of an approval for the same formation(s)/pool(s).

7) Does each contiguous area of application contain production data in the applied-for formation(s)/pool(s)?

Select YES if the area of application has at least one well with enough production history to allow for the submission of volumetric reserves data that can clearly support the need for the requested special well spacing in the applied-for formation(s)/pool(s).

Sufficient production history and volumetric reserves data from wells within the entire application area are required. Additional production and volumetric reserves data from producing wells in surrounding areas should also be included to fully support an application.

Select NO if each contiguous area of application does not contain production data in the applied-for formation(s)/pool(s).

8) Is the proposed DSU size greater than or equal to the previously approved area?

Select YES if the DSU size applied for is greater than or equal to the DSU size in the previously approved area.

Select No if the DSU size applied for is less than the DSU size in the previously approved area.

9) Are you applying for a standalone DSU?

Section 4.050(1) of the *OGCR* stipulates that if a fractional tract of land differs in size by more than 5 per cent from a standard DSU, an application must be made to have the fractional tract of land approved as a DSU.

Select YES if the tract of land is at least half the size of a standard DSU and you are requesting that the fractional tract of land be considered as a standalone DSU.

10) Enter the area of the fractional tract of land in hectares.

11) Is there common ownership between your tract of land and an adjacent DSU?

Select YES if there is common ownership between the area of application and an adjacent DSU to the east or west. If common ownership exists, the fractional tract of land can be adjoined to the adjacent DSU.

If you select NO, the application cannot be filed.

12) Enter the DSU size.

All Reduced DSU applications must propose a DSU size. If you are submitting a Change in Target Area application and you have answered NO to question 3, you must enter the size of the current DSU in the area of application. Sizes are

- 1 Legal Subdivision
- 2 Legal Subdivisions
- 1 Quarter Section
- 1 Half Section
- 1 Section
- Special DSU (only available for fractional tract applications)

13) Enter the DSU orientation.

If the DSU size is 2 LSDs or 1 half section, select a north-south or east-west orientation.

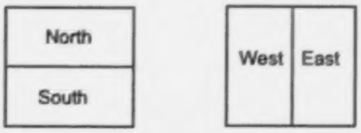


Figure 7.9. North/south and east/west orientation for a 1 section DSU

14) The standard target area locations for the requested DSU size are based on Section 4.030 of the OGCR.

The standard target areas for Area 1 and Area 2 are given in the following table.

DSU size	Area 1 description	*OGCR*	Area 2 description	OGCR
1 section	Central part of the section having sides 300 m from the boundaries of the section and parallel to them	Central area Sections 1.020(3)(a) and 4.030 (1)(a)	Central part of the section having sides 300 m from the boundaries of the section and parallel to them	Sections 1.020(3)(a) and 4.030 (2)(a)
1 half section	Central part of the southwest or northeast quarter section as if the quarter section were a quarter-section DSU	Central area SW or NE quarter section Sections 1.020(3)(b) and 4.030(1)(b)	LSD 6 or 16	Section 4.030 (2)(b)
1 quarter section	Central part of the quarter section having sides 200 m from the boundaries of the quarter section and parallel to them	Central area Sections 1.020(3)(b) and 4.030 (1)(b)	LSD 6, 8, 14, or 16	Section 4.030(2)(c)
2 LSDs	Central part of the southwest or northeast LSD of the quarter section as if the LSD were a 1 LSD DSU.	Central area SW or NE LSD Sections 1.020(3)(c) and 4.030 (1)(c)	The northwest quarter of the southwest or northeast LSD of the quarter	NW quarter of the SW or NE LSD Section 4.030(2)(d)
1 LSD	Central part of the LSD having sides 100 m from the boundaries of the LSD and parallel to them	Central area Sections 1.020(3)(c) and 4.030 (1)(c)	Consists of the northwest quarter of the LSD	NW quarter of the LSD Section 4.030 (2)(e)

15) Do you want to proceed with the standard target area in accordance with Section 4.030 of the OGCR*?*

Select YES if you are proposing the standard target area.

Select NO to request a nonstandard target area and describe it in question 16. An application requesting nonstandard target areas must be filed as a Change in Target Area application subtype. Standard target areas cannot be selected for fractional DSUs; therefore, a target area description must be entered in question 16. For a Fractional Tract of Land application, you must select NO. (See Section 7.2.7.2.)

16) If NO, enter the proposed target area description.

Enter a description of the proposed target area.

The typical target area for a fractional DSU, whether it is being proposed as a standalone DSU or is to be added to an adjacent DSU, is 300 m from and parallel to the sides of the DSU.

7.6.2.8 Change in Approval Holder

1) Does each applied-for holding have common ownership at the lessor and lessee levels?

Select YES if your proposed holding contains only a single DSU or whole and contiguous DSUs of common ownership (Section 5.200 of the *OGCR*).

If you select NO, the application cannot be filed.

2) Enter the well density of the holdings where the approval holder is to change.

The well density entered on the form must match the well density in the existing approval. Well density is defined as the number of wells per pool per area. Enter the well density and then select the well density area. Possible well density areas are

- 1 Quarter Legal Subdivision
- 1 Legal Subdivision
- 2 Legal Subdivisions
- 1 Quarter Section
- 1 Half Section
- 1 Section
- 2 Section
- 3 Section
- 4 Section
- Per Holding
- Limited by Buffer Distance
- Limited by Buffer and Interwell Distances
- Limited by Interwell Distance
- Per Pool
- See Special Provision

3) Enter the buffer zone distance of the holdings where the approval holder is to change.

Enter the buffer zone distance from the boundaries of each holding in metres of the existing approval. The buffer zone distance entered must match the existing approval.

3a) Enter the buffer orientation of the holdings where the approval holder is to change.

Select the boundaries of the holding that the buffer zone distance applies to. The selected boundaries must match the existing approval.

4) Do the holdings where the approval holder is to change have an interwell distance?

If you select YES, enter the approved interwell distance in question 4a.

If No, question 4a is not required.

4a) If YES, enter the interwell distance of the holdings where the approval holder is to change.

The interwell distance entered must match the existing approval.

7.6.2.9 Rescinding Holdings or Units

1) Does your area of application include entire DSUs?

Select YES if each area of application contains whole DSUs. Note that you can only use the Rescind application form to remove a DSU(s) from a holding where a lease(s) has expired and reverted back to the Crown or if you wish to rescind all or a portion of the holding in favour of the standard spacing specified in Part 4 of the *OGCR*.

If you select NO, the application cannot be filed.

2) Enter the well density to be rescinded.

The well density entered on the form must match the well density in the existing approval being rescinded. Well density is defined as the number of wells per pool per area.

Enter the well density and then select the well density area. Possible well density areas are

- 1 Quarter Legal Subdivision
- 1 Legal Subdivision
- 2 Legal Subdivisions
- 1 Quarter Section
- 1 Half Section
- 1 Section
- 2 Section
- 3 Section
- 4 Section
- Per Holding
- Limited by Buffer Distance
- Limited by Buffer and Interwell Distances
- Limited by Interwell Distance
- Per Pool
- See Special Provision

3) Enter the buffer zone distance to be rescinded.

Enter the buffer zone distance from the boundaries of each holding/unit in metres of the existing approval being rescinded. The buffer zone distance entered must match the existing approval.

3a) Enter the buffer orientation to be rescinded.

Select the boundaries of the holding/unit that the buffer zone distance applies to. The selected boundaries must match the existing approval.

4) Is there an interwell distance to be rescinded?

If you select YES, enter the approved interwell distance in question 4a.

If No, question 4a is not required.

4a) If YES, enter the interwell distance to be rescinded.

The interwell distance entered must match the existing approval.

7.6.3 Well Productivity and Volumetric Reserves Form

No well productivity or volumetric reserves information is required for applications to rescind a holding, to change an approval holder, or to establish a fractional DSU.

7.6.3.1 Required Production/Volumetric Reserves Information

Production and volumetric reserves information for each applied-for formation or pool is required as follows:

Quick application path: Production data from all applied-for formations in an adjacent DSU within a previously approved area of spacing is mandatory. Production and volumetric reserves data within the application area are not required. (See Section 7.4.1.)

Standard application path: Production and volumetric reserves data from a minimum of one well within each contiguous area of application or each applied-for holding/unit are mandatory. (See Section 7.4.2.)

Nonstandard application path: Production and volumetric reserves data from a minimum of one well either within the application area or outside the application area are mandatory. (See Section 7.4.3.)

7.6.3.2 Populating the Well Productivity and Volumetric Reserves Form

Selected wells should represent the type of development being proposed (e.g., vertical; horizontal wells) and typical performance in the area. The selected wells should have production information from each formation/pool and substance being applied for. Once you have opened the Well Productivity/Volumetric Reserves form, select "Add Well." This will bring you to the Well Productivity Details page, where you will enter the well licence number and select the appropriate unique well identifier (UWI) from the drop-down list.

It is helpful to have a list of representative UWIs and their licence numbers prepared in advance of logging into the DDS system to prepare a spacing application. Well licence numbers can be obtained from the Well Spacing Map using the "show well information icon."

Once a UWI has been selected, the form will populate with ERCB production data. These data can be edited in the Applicant Data section of the Well Productivity Form and should be revised if the auto-populated data are not current or correct. In the case of a commingled well, production data for each applied-for formation are required. Any changes to ERCB data must be addressed and explained in the "Reason for Production Form Edits" attachment. Applicants should have this information gathered before starting an application so they can quickly identify and address any inconsistency and help avoid requests for additional information from the ERCB.

For commingled wells, the same UWI can be used by selecting the same well licence number multiple times to provide production/volumetric data that can be allocated to each specific producing formation within a well. (See Section 1.1.2: Spacing and Commingled Production.)

If selecting a confidential well to support an application, all production/volumetric information must be provided. All confidential data provided in support of an application are public and viewable in IAR Query.

For each well used to provide production information, the following data must be provided where applicable:

- well licence number
- unique well identifier (UWI)
- producing formation
- producing pool
- well status
- on-production date
- last date the well reported production
- the depth to the top of the first perforation
- the depth to the bottom of the last perforation
- the true vertical depth from the kelly bushing (KB) to the top of the first perforation
- the true vertical depth measured to the bottom of the last perforation
- initial operated-day rate based on actual hours of the first month in which oil/gas is produced
- last operated-day rate
- last calendar-day rate based on calendar days in the month in which oil/gas was last being produced
- current ratio of water production to gas production (WGR)
- cumulative gas/oil production
- cumulative water production
- cumulative condensate production

For wells where volumetric reserves information has been provided, a production plot and decline analysis for each well is required. The analysis must also include an explanation of the parameters used to populate the volumetric form (e.g., the net pay used is from the XX/XX-XX-XXX-XXWX well that is in the area of application).

If the number of wells per area calculated on the volumetric form is less than the well density requested, the following warning message appears: "The UWI shows a 'max number of wells per area' less than the requested well density in the application. Confirm your values before saving." This information message requests you to review your data and perhaps change the well density request or provide additional supporting information. A written justification for production and volumetric data used must be included with the application.

The following table describes the fields on the Production and Volumetric Form and the values to be entered.

Field	Description
Licence Number	The well licence number.
UWI	From the drop-down list, the UWI to be used to enter production and/or volumetric reserves information.
ERCB/APPLICANT DATA	
Producing Formation	The name of the producing formation being applied for.
Pool	The name of the pool being applied for.
Status	The current well status.
On Production Date	The date the well came on production.
Last Month Produced	The last date the well reported production.
Perforated Interval(s) (measured in metres KB)	
Perf Top	The depth to the top of the first perforation in the producing formation.
Perf Base	The depth of the bottom of the last perforation in the producing formation.
TVD Top	The true vertical depth from the KB to the top of the first perforation.
TVD Base	The true vertical depth measured to the bottom of the last perforation.
Initial Operated Day Rate	The daily production rate based on actual hours of the first month in which oil/gas is produced.
Current/Last Operated Day Rate	The daily production rate based on actual hours of the current/last month that gas/oil is produced.
Current/Last Calendar Day Rate	The daily production rate based on calendar days of the current/last month that gas/oil is produced.
Current WGR	The current ratio of water production to gas production.
Cumulative Gas/Oil Production	The total volume of gas or oil produced.
Cumulative Water Production	The total volume of water produced.
Cumulative Condensate Production	The total volume of condensate produced.
VOLUMETRIC DATA	
DSU Area	The area used to calculate the volume of oil/gas. This should be the standard DSU size.
Net Pay	The average net pay thickness of the well, DSU, or pool, if available. For horizontal wells, use vertical pay values.
Average Porosity	The average percentage of porosity in the reservoir.
Average Gas/Oil Saturation	The percentage of gas or oil saturation in the reservoir.
Ti	The initial reservoir temperature (K° = C° + 273.15).
Zi	The initial gas compressibility factor.
Pi	The initial reservoir pressure (kPa absolute).
Inverse Formation Volume Factor	Gas: Inverse Gas Formation Volume Factor. 1/(101.325*Zi*Ti/(288.155*Pi)) = 1/Bgi Oil: The inverse of the initial formation volume factor for the oil in the reservoir (1/Boi).

(continued)

Field	Description
Coal Bulk Density	The density of the coal in situ (g/cc).
Gas Content	The amount of methane gas contained in a coal (cc/g).
Original Reserves in Place	Original gas/oil reserves in place. OGIP (m^3) = A* h * ø * (Sg) * (1/Bgi) OGIP (m^3) = A* h * Gas Content * Coal Bulk Density OOIP (m^3) = A* h * ø * (So) * (1/Boi)
Pool Recovery Factor	The current estimated percentage of recovery of the pool.
EUR from Decline	Estimated ultimate recoverable reserves based on decline analysis.
Calculated Recovery Factor	Well recovery factor. RF = EUR/OGIP or OOIP
Drainage Area at Pool Recovery Factor	Well drainage area (ha). EUR/ [h * ø * (Sg) * (1/Bgi)* Ri] or EUR/ [h * ø * (So) * (1/Boi)* Ri] or EUR/[h * Gas Content * Coal Bulk Density * Ri]
Max. Number of Wells per Area	DSU area/Drainage area

Appendix A References

How to Use This Directive	Energy Resources Conservation Act Energy Resources Conservation Board Rules of Practice Directive 019: ERCB Compliance Assurance—Enforcement
When to Use Schedule 1	ST103: Field and Pool Code List Energy Resources Conservation Act, Section 26
Notification Guidelines	Energy Resources Conservation Act, Section 26 Directive 056: Energy Development Application Guide, Unit 1, Step 4: Emergency Response Plan

Unit 1—Equity

1.1 Rateable Take	Oil and Gas Conservation Act, Section 36 Decision 85-5 Directive 032: Common Gas Purchaser and Related Matters, Board Policy and Views Decision 91-8 Directive 040: Pressure and Deliverability Testing Oil and Gas Wells
1.2 Common Purchaser	Oil and Gas Conservation Act, Sections 50, 51, 55, and 56 Directive 32: Common Gas Purchaser and Related Matters, Board Policy and Views Decision 91-8
1.3 Common Carrier	Oil and Gas Conservation Act, Sections 48, 55, and 56 Directive 032: Common Gas Purchaser and Related Matters, Board Policy and Views Decision 91-8 Decision 2006-021 JP-05: A Recommended Practice for the Negotiation of Processing Fees
1.4 Common Processor	Oil and Gas Conservation Act, Sections 53, 55, and 56 Directive 32: Common Gas Purchaser and Related Matters, Board Policy and Views Decision 91-8 Decision 2006-021 JP-05: A Recommended Practice for the Negotiation of Processing Fees
1.5 Compulsory Pooling	Oil and Gas Conservation Regulations, Section 5.005 Oil and Gas Conservation Act, Sections 80, 85, and 86 Examiner Report 91-6 Examiner Report 95-2

Unit 2—Conservation

2.1 Enhanced Recovery Scheme	Oil and Gas Conservation Act, Section 39(1)(a) Directive 051: Injection and Disposal Wells IL 94-13: Progress Report Requirements – Conventional Recovery Schemes IL 96-2: Progress Report Requirements for Miscible Flood Schemes GB 2000-8: Process Changes to Disposal Well Applications Bulletin 2004-16: Chances to Enhanced Oil Recovery Application Requirements and Review Process Bulletin 2004-30: Directive 065: Resources Applications for Conventional Oil and Gas Reservoirs Enhanced Recovery Scheme—Application Changes Application Form, Requirements, and Process
2.2 Enhanced Oil Recovery Project	*Rescinded*
2.3 Enhanced Recovery Recognition and Good Production Practice	*Rescinded*
2.4 Concurrent Production	Oil and Gas Conservation Act, Section 39(1)(e) Directive 060: Upstream Petroleum Industry Flaring Guide

Unit 3—Production Control

3.1 Commingled Production	Oil and Gas Conservation Regulations, Sections 3.050 and 3.060 ID 99-1: Gas/Bitumen Production in Oil Sands Areas—Application, Notification, and Drilling Requirements
3.3 Good Production Practice (Primary Pools)	Oil and Gas Conservation Regulations, Section 10.060 Monthly MRL Order Directive 060: Upstream Petroleum Industry Flaring Guide Directive 007-1: Allowables Handbook ID 99-2: Revised Policy on Administration of Oil MRLs and Overproduction
3.4 GOR Penalty Relief	Oil and Gas Conservation Regulations, Section 10.060
3.5 Special MRL	Oil and Gas Conservation Regulations, Section 10.060
3.6 Gas Allowable	Oil and Gas Conservation Regulations, Sections 4.050, 4,070, 10.095, and 10.300 ID 94-2: Revisions to Oil and Gas Well Spacing Administration ID 94-5: Consolidation of Regulations for Off-Target Penalty Factor Determination IL 85-10: Maximum Daily Rate of Production for Gas Wells

Unit 4—Disposal/Storage

4.1 Class I-IV Disposal	Oil and Gas Conservation Act, Sections 39(1)(c) and 39(1)(d) Directive 051: Injection and Disposal Wells Directive 056: Energy and Development Application Guide

	Directive 058: Oilfield Waste Management Requirements for the Upstream Petroleum Industry GB 2000-8: Process Changes to Disposal Well Applications
4.2 Acid Gas Disposal	Oil and Gas Conservation Act, Section 39(1)(d) Directive 051: Injection and Disposal Wells GB 2000-8: Process Changes to Disposal Well Applications
4.3 Underground Gas Storage	Oil and Gas Conservation Act, Section 39(1)(b) Directive 051: Injection and Disposal Wells
Unit 5—Corporate Changes	
5.1 Change of Name of Approval Holder	Oil and Gas Conservation Regulations, Section 15.080
5.2 Change of Approval Holder	Oil and Gas Conservation Regulations, Section 15.080
Unit 6—Gas and Ethane Removal	Report 87-A: Gas Supply Protection for Alberta Gas Resources Preservation Act, Section 2 ST48: Alberta Gas Removal and Related Applications Bulletin 2006-42: Gas Removal Data System Compliance Process Directive 019: ERCB Compliance Assurance—Enforcement
Unit 7—Special Well Spacing	See Unit 7 for references

To obtain current ERCB documents, visit the ERCB Web site (www.ercb.ca) or contact ERCB Customer Contact Centre at 403-297-8311 or by fax at 403-297-7040.

Appendix B

Notification Templates

Sample Template of Company-to-Company Notification

Sample Notice Letters for Commingling Using the DE or SD Process

Sample Template of Company-to-Company Notification

(use for most application types except for well spacing applications)

[Date]

[Offset Company]
[Address]

Attention: [Offset Owner]

Dear [Sir/Madam]:

Application for [type of application]
[List wells or pool]

[Company X] proposes to apply to the Energy Resources Conservation Board (ERCB/Board) for approval to [describe the application]. A copy of the proposed application is enclosed. If you have questions about this application, do not hesitate to contact the undersigned at [telephone number]. If you have any concerns respecting the potential for the application to affect your interest, send a letter to me by fax to [facsimile number], by mail to the letterhead address, or by e-mail to [e-mail address] stating your concerns.

If you do not respond to this letter on or before [date—at least 15 working days from the date of this letter], we will assume that you have no objections to the proposed application and the ERCB will process the application without further contact with you.

The ERCB application process is a public process, and all documents filed with the ERCB will be placed on the public record unless otherwise authorized by the Board in accordance with Section 12 of the *Energy Resources Conservation Board Rules of Practice*, *Energy Resources Conservation Act*.

Yours truly,

[Company]

Sample Notice Letters for Commingling Using the DE or SD Process

Sample Template of Company-to-Company Notification Letter

To be used for notification of offsetting well licensees when commingling production using the DE or SD process

[Date]

[Name]
[Address]
[Address]
[Address]

Attention:

Notification of commingling of gas/oil production
[Within a development entity OR using the self-declared process]
[UWI location]
[list intervals commingled] mKB

[Company Name] has used Energy Resources Conservation Board's [development entity OR self-declared process] to commence unsegregated production at the subject well in the intervals noted above. A requirement of the process necessitates that licensees of active wells in the section of interest and offsetting drilling spacing units be notified of the commencement or change to the production operations of any well using the [development entity OR self-declared process].

If you have any concerns or questions respecting the potential of unsegregated production to affect your interest, do not hesitate to contact the undersigned at [telephone number].

Yours truly,

[Contact Name]
[Company]

Sample Template of Notification Letter to Be Used for Notifying Freehold Mineral Lessor *Prior* to Unsegregated Completion

To be used if the lessors are not common for the different strata within the wellbore planned for commingled production when using the DE or SD process

[Date]

[Name]
[Address]
[Address]
[Address]

Attention:

Notification of commingling of gas/oil production
[Within a development entity OR using the self-declared process]
[UWI location]
[list intervals commingled] mKB

[Company Name] intends to used Energy Resources Conservation Board's [development entity OR self-declared process] to commence unsegregated production at the subject well in the intervals noted above. A requirement of the process necessitates that the Freehold mineral lessor(s) be notified if the lessors are not common for the different strata within the wellbore where commingling is proposed. The proposed commingling may affect the proportion of royalty assigned to your mineral holdings.

If you have any concerns or questions respecting the potential of unsegregated production to affect your interest, do not hesitate to contact the undersigned at [telephone number] within 15 working days from the date of this letter. If you do not respond within the time period noted, commingled production in the subject well will commence without further notice to you.

Yours truly,

[Contact Name]
[Company]

Sample Template of Notification Letter to Be Used for Notifying Freehold Mineral Lessor *After* Unsegregated Completion Has Occurred

To be used to notify Freehold mineral lessors in the DSU of the commingled well and in offsetting DSUs when using the DE or SD process

[Date]

[Name]
[Address]
[Address]
[Address]

Attention:

Notification of commingling of gas/oil production
[Within a development entity OR using the self-declared process]
[UWI location]
[list intervals commingled] mKB

[Company Name] has used the Energy Resources Conservation Board's [development entity OR self-declared process] to commence unsegregated production at the subject well in the intervals noted above. A requirement of the process necessitates that the Freehold mineral lessor(s) in the drilling spacing unit (DSU) of the commingled well and offsetting DSUs be notified when this process is used.

If you have any concerns or questions respecting the potential of unsegregated production to affect your interest, do not hesitate to contact the undersigned at [telephone number].

Yours truly,

[Contact Name]
[Company]

Appendix C

ERCB *Energy Resources Conservation Board*

Application for Gas-Oil Ratio (GOR) Penalty Relief
Form O-33

This form is to be used for smaller, less complex pools only. For detailed application requirements, see Directive 065, Unit 3: Production Control. A covering letter should state the reason GOR Penalty Relief is being requested and should be made on behalf of all operators in the pool.

Company Name ____________________ **On behalf of** (N/A ☐) ____________________

Field and Pool Name ____________________

Gas Conservation

Is solution gas currently being conserved? Yes ☐ No ☐

If gas conservation is planned for the future, identify the tie-in location and provide an implementation schedule.

If gas conservation is not considered feasible, include economic analysis showing capital costs, product price forecasts, total revenue (including liquids), payout time, and rate of return.

Performance Characteristics

Base MRL ____________________ m^3/d/well Base GOR ____________________ m^3/m^3

Well Location (Unique Well Identifier)	On Production Date	Cumulative Oil Production (m^3)	Capability (m^3/d)	GOR (m^3/m^3)

Pool Reserves (company's interpretation)

Area (hectares) ____________________

N (10^3 m^3) ____________________

R_i ____________________

R_i N (10^3 m^3) ____________________

Pressure Data

P_i ____________________ kPa(ga) P_b ____________________ kPa(ga)

Last measured pressure ____________________ kPa(ga)

Date ____________________ Well ____________________

Where appropriate, attach material balance calculations.

(continued)

Geology

Discuss the potential for further pool development.

Recompletion Potential

Comment on recompletion potential or any measures taken to reduce gas production.

Enhanced Recovery Potential

Impact on Primary Oil Recovery

Correlative Rights — Include an up-to-date map showing lessee and lessor ownership.

(Note: If pool is multiwell and of mixed ownership, concurrence in writing is required from all operators.)

Appendix D Transfer of Approval

AGREEMENT TO TRANSFER APPROVAL(S)

BETWEEN ____
(*company name*)
of the City of ______________________________ in the Province of Alberta,

referred to as the **Transferor**, and ________________________ of the City
(*company name*)

of ____________________ in the Province of Alberta, referred to as the **Transferee**.

The **Transferor**, who is the holder of Board Approval No. ________, dated the ___day of ____ (or of the attached list of Board Approvals) for a ________________________ scheme,
(*type of scheme(s)*)
for good and valuable consideration, transfers to the **Transferee** the Approval(s) and all the **Transferor's** right and title in the Approval(s).

The **Transferee** agrees to the transfer of the Board Approval (or attached list of Board Approvals), acknowledges that it is aware of the details and conditions of the approved ____________________ scheme(s), and agrees to carry out the scheme(s) as approved.
(*type of scheme(s)*)

The address of the **Transferee** in Alberta is

____

____.

Dated at ______________________, on ______________________________.
(*city*)

Signature:________________________
Authorized Representative of Transferor

Signature:________________________
Authorized Representative of Transferee

Appendix E ERCB Staff Contacts*

UNIT 1 – EQUITY

1.1 Rateable Take	Karine Fisher	(403) 297-8490
1.2 Common Purchaser	Karine Fisher	297-8490
1.3 Common Carrier	Karine Fisher	297-8490
1.4 Common Processor	Karine Fisher	297-8490
1.5 Common Pooling	Karine Fisher	297-8490

UNIT 2 – CONSERVATION

2.1 Enhanced Recovery Scheme	Rick Parkyn	297-2391
2.4 Concurrent Production	Rick Parkyn	297-2391
2.5 Pool Delineation and Ultimate Reserves	Rick Parkyn	297-2391

UNIT 3 – PRODUCTION CONTROL

3.1 Commingled Production	Karine Fisher Sukh Mangat	297-8490 297-4151
3.3 Good Production Practice (Primary Depletion Pool)	Rick Parkyn	297-2391
3.4 Gas-Oil Ratio Penalty Relief	Rick Parkyn	297-2391
3.5 Special Maximum Rate Limitation	Rick Parkyn	297-2391
3.6 Gas Allowable	Sukh Mangat Karine Fisher	297-4151 297-8490

UNIT 4 – DISPOSAL/STORAGE

4.1 Class I–IV Disposal	Rick Parkyn	297-2391
4.2 Acid Gas Disposal	Joe McIntosh	297-8415
4.3 Underground Gas Storage	Joe McIntosh	297-8415

UNIT 5 – CORPORATE CHANGES

5.1 Change in Name of Approval Holder	Christine Helmer	297-8529
5.2 Change of Approval Holder	Christine Helmer	297-8529

UNIT 6 GAS AND ETHANE REMOVAL

Karine Fisher	297-8490

UNIT 7 – APPLICATION FOR SPECIAL WELL SPACING

Mary Anne Cairns	297-8563
Kerry Murphy	662-3981

All ERCB e-mail addresses are standardized as follows:
firstname.lastname@ercb.ca

Appendix F

Enhanced Recovery (ER) Scheme Application Form

ERCB Energy Resources Conservation Board

Resources

Enhanced Recovery (ER) Scheme

DAY	MONTH	YEAR

APPLICANT'S REFERENCE

____

The applicant certifies that the information provided here and in all supporting documentation is correct and in accordance with all regulatory requirements or as directed by the Energy Resources Conservation Board.

1 APPLICATION TYPE

1. Type of ER scheme being proposed or amended:

☐ Waterflood

☐ Immiscible gas/Solvent flood

☐ Miscible flood

☐ Gas cycling

☐ Other

2. Is this application for a new ER scheme or an amendment to an existing ER scheme approval? New ☐ Amendment ☐

If you select "New,"

- *proceed to Section 2; do not answer questions 3 and 4;*
- *attachments required: Isopach Map, Well Log(s), Pressure Data, and Interpretation.*

3. What is the existing ERCB approval number proposed for amendment? ☐

4. Type of amendment:

☐ Add injection well location(s)

☐ Amend approval area

☐ Amend approval conditions

☐ Scheme termination

If you select "Add injection well location(s)" only,

- *you must respond to questions in Sections 2, 3, and 5. Do not respond to questions in Section 4.*

If you select "Amend approval area" only,

- *you must respond to questions in Sections 2, 4, and 5. Do not respond to questions in Section 3.*

If you select "Add injection well location(s)" and "Amend approval area,"

- *you must respond to questions in Section 2, 3, 4, and 5.*

If you select "Amend approval conditions" only,

- *you must respond to questions in Section 2 and 5. Do not respond to questions in Sections 3 and 4.*

If you select "Scheme termination" only,

- *you must respond to questions in Section 2 and 5. Do not respond to questions in Sections 3 and 4 or question 18 in Section 5.*

2 OWNERSHIP AND NOTIFICATION INFORMATION

5. The primary applicant must
   a) be the proposed approval holder for a new scheme or the current approval holder for an existing scheme, and
   b) represent all well licensees in the proposed approval area.

   Have these requirements been met? Yes ☐ No ☐

   If your answer is "No," you cannot submit this application.

6. An ER scheme application cannot be submitted until notification of all well licensees has been completed in accordance with *Directive 65.*

   Has notification been completed in accordance with *Directive 65*? Yes ☐ No ☐

   If your answer is "No," you cannot submit this application.

7. Are there outstanding concerns from well licensees? Yes ☐ No ☐

   If yes, the Licensee Concerns attachment must be submitted as part of the application, in accordance with *Directive 65.*

3 PROPOSED INJECTION WELL LOCATIONS AND INJECTION INTERVALS

8. An ER scheme application cannot be submitted unless the proposed injection wells have been drilled.

   Have the proposed injection wells been drilled? Yes ☐ No ☐

   If your answer is "No," you cannot submit this application.

9. An ER scheme application cannot be submitted unless the source of the proposed injection fluid has been secured.

   Has the source of the proposed injection fluid been secured? Yes ☐ No ☐

   If your answer is "No," you cannot submit this application.

10. Provide the following for the proposed injection well locations:

Well Licence Number	Unique Well Identifier (UWI)							Injection Interval (TVD mKB)		Porosity Interval (TVD mKB)		Fluid Interface (TVD mKB) If applicable	
	LE	LSD	SEC	TWP	RG	MER	ES	Top	Base	Top	Base	Gas/Oil	Oil/Water

11. What type of injection fluid, as identified by *Directive 051*, will be used?

☐ Class II – produced water (brine) without H_2S

☐ Class II – produced water (brine) with H_2S

☐ Class III – hydrocarbons or other gases without H_2S

☐ Class III – hydrocarbons or other gases with H_2S

☐ Class IV – non-saline water

If you select "Class II – produced water (brine) without H_2S" only,
- *do not respond to question 11a. Proceed to question 12.*

If you select "Class III – hydrocarbons or other gases without H_2S" only,
- *do not respond to question 11a, and*
- *proceed to question 12.*

If you select "Class IV – non-saline water,"
- *do not respond to question 11a, and*
- *proceed to question 12.*

11a. If an injection fluid contains H_2S and an emergency response plan (ERP) is required, the ERCB must ensure that an up-to-date ERP is in place prior to its decision on the application.

Is an ERCB-approved ERP incorporating the proposed scheme in place? Yes ☐ No ☐

If no, a discussion addressing the status of the ERP must be included in the Application attachment, in accordance with *Directive 65.*

12. Will injection commence in all proposed injection wells within three months of receipt of approval? Yes ☐ No ☐

If no, a discussion addressing the anticipated commencement of injection and the reason for the delay must be included in the Application attachment, in accordance with *Directive 65.*

4 PROPOSED APPROVAL AREA

13. Is the entire proposed approval area within the ERCB's Pool Order boundary for the subject pool? Yes ☐ No ☐

If you select "No," you must respond to question 15.

14. Does your interpretation of pool extent correspond to the ERCB's Pool Order boundary for the subject pool? Yes ☐ No ☐

If you select "No," you must respond to question 15.

15. Is the difference in pool delineation interpretation pertinent to the proposed ER scheme, in accordance with *Directive 65*? Yes ☐ No ☐

Provide a discussion of the difference in pool delineation and the pertinence to the proposed ER scheme in the Application attachment, in accordance with *Directive 65.*

5 SCHEME DETAILS

16. Is the scheme area currently administered under good production practice (GPP)? Yes ☐ No ☐

17. Will produced gas from the ER scheme area be conserved, in accordance with *Directive 060* requirements? Yes ☐ No ☐

18. What is the proposed voidage replacement ratio (VRR), on a monthly basis, for the scheme?

The ERCB normally specifies a VRR of 1.0 to fully maintain reservoir pressure. If the VRR will not be 1.0, provide a technical justification in the Application attachment, in accordance with *Directive 65.*

19. Is or will any gas-cap gas be produced from the subject pool during the operation of the ER scheme? Yes ☐ No ☐

If yes, include a discussion on the potential for fluid migration into the gas cap in the Application attachment, in accordance with *Directive 65.*

If you select "No," do not respond to questions 20, 20a, 20b, or 20c.

20. Is gas-cap gas currently being produced from the scheme area? Yes ☐ No ☐

If you select "No," do not respond to questions 20a, 20b, or 20c.

20a. Has the appropriate concurrent production (CCP) approval been issued? Yes ☐ No ☐

If you select "Yes," do not respond to questions 20b or 20c.

20b. An application for CCP is required. Has an application for CCP been registered? Yes ☐ No ☐

If you select "No," do not respond to question 20c.

20c. If yes, provide the CCP application number.

Appendix G

Gas and Ethane Removal Forms

Short-Term Gas Removal Application

Long-Term Gas Removal Application

Short-Term Ethane Removal Application

ERCB Energy Resources Conservation Board

Short-Term Gas Removal Application

For permit to remove gas from Alberta in volumes of not more than
3 billion cubic metres (m^3) and for a term of not more than 2 years

This application is made under Section 2 of the *Gas Resources Preservation Act.*

For a new permit, complete Part A; for amendment of an existing permit, complete the appropriate portions of Part B; for the rescission of a permit, complete Part C. The ERCB reserves the right to require an applicant to furnish additional information as it deems necessary to complete or supplement the application.

PART A (for a new permit)

Total volume of gas proposed for removal (m^3)____________________

Proposed term of permit and commencement/termination dates____________________

____

PART B (for an amendment to an existing permit; fill in only those portions for the desired amendment)

Amendment requested for Permit No.____________________

Amendment is for

☐ Total authorized volume: Existing volume (m^3)____________________

Proposed volume (m^3)____________________

☐ Term: Existing term and commencement/termination dates ____________________

____

____

Proposed term and commencement/termination dates____________________

____

☐ Change of permit holder

Existing permit holder ____________________

Proposed permit holder ____________________

☐ The proposed permit holder agrees to assume and perform all of the obligations and duties of the existing permit holder under the permit.

☐ Other (describe in detail):

____

____

____

____

____

(continued)

PART C (for the rescission of a permit)

Permit(s) No. to be rescinded ______________________________

Reporting Requirements Associated with a Gas Removal Permit

A monthly gas removal permit statement must be completed for each permit and filed electronically with the ERCB by midnight on the 28th day of the month following the data month. The data month is the month when the gas was delivered. If the 28th is not a business day, the deadline falls on the next business day. The form must be completed and filed for each permit even if no gas has been removed. Detailed reporting instructions are set out in *Bulletin 2006-42: Gas Removal Data System Compliance Process*, available on the ERCB Web site www.ercb.ca. Questions on reporting may be directed to the ERCB Economics Group at 403-297-5836.

ERCB Energy Resources Conservation Board

Long-Term Gas Removal Application

For permit to remove gas from Alberta in volumes greater than
3 billion cubic metres (m^3) or for terms greater than 2 years

This application is made under Section 2 of the *Gas Resources Preservation Act*.
Use this form for new permits and amendments of existing permits.

Remember to answer all questions and to add attachments if the space provided is inadequate. The ERCB reserves the right to require an applicant to furnish additional information as it deems necessary to complete or supplement the application.

1. Request is for ☐ New Permit

   ☐ Amendment to Permit No. ____________________

2. ☐ Change of permit holder (amendment of permit)

   Existing permit holder ____________________

   Proposed permit holder ____________________

   ☐ The proposed permit holder agrees to assume and perform all of the obligations and duties of the existing permit holder under the permit.

3. Permit(s) No. to be rescinded (if applicable) ____________________

4. a) Total volume of gas proposed for removal:

   Existing volume authorized (if applicable) (m^3) ____________________

   Proposed volume authorized (m^3) ____________________

   b) Gas required for fuel to transport gas from Alberta: Does the proposed total authorized volume of gas include all fuel needed to transport the gas from the Alberta border to the intended market(s)?

   ☐ Yes ☐ No

   If No, how would such fuel gas be accounted for? (Any gas, including fuel gas, removed from Alberta must be authorized by and reported under a gas removal permit.)

   ____

(continued)

5. Term of permit

Existing term and commencement date (if applicable) ______________________

Proposed term and commencement date ______________________

If the proposed term is greater than 15 years, attach a discussion describing how the circumstances relating to the sales contract involved could be considered as special ones that would justify the requested term, including an indication as to whether the proposed gas removals could proceed under a 15-year permit and, if not, why not.

6. Name of proposed market(s), and the location and type of end-use customer(s) to be served under the permit

7. Are arrangements in place for transporting the applied-for gas from the Alberta receipt point(s) to the intended end-use customer(s)?

☐ Yes ☐ No

If No, describe the transportation arrangements involved, including comments on when you anticipate that any new facilities to be built would be completed.

(continued)

8. Provide a summary of the pricing arrangements and how they were determined for the applied-for gas. Comment on any provisions to ensure that prices continue to reflect market conditions throughout the term of the permit.

9. Discuss how the applied-for removal of gas would be in the Alberta public interest.

(continued)

10. Attach a table in the required format (described in *Directive 065: Resources Applications for Conventional Oil and Gas Reservoirs*) of the lands/zones that would supply the permit or amended permit, including
    - the legal description of all the lands involved,
    - the zone or zones under the applicant's control for the lands in question, and
    - the working interest ownership under the applicant's control for the lands/zones.

11. Attach a summary of the total gas reserves volume associated with the lands serving the proposed permit, together with a list of all commitments that would be served by the reserves portfolio involved, including the proposed permit and other permits (specify the number of each existing permit, as well as remaining authorized commitment), intra-Alberta commitments (such as industrial, commercial, or residential contracts or corporate warranties to other companies), and any other commitments.

    Total gas reserves volume associated with the lands serving the proposed permit: ______________________ m^3

    Commitments to be served by the reserves portfolio involved:

Permit No. or other commitment (describe)	Total volume of commitment (m^3)

Reporting Requirements Associated with a Gas Removal Permit

A monthly gas removal permit statement must be completed for each permit and filed electronically with the ERCB by midnight on the 28th day of the month following the data month. The data month is the month when the gas is delivered. If the 28th is not a business day, the deadline falls on the next business day. The form must be completed and filed for each permit even if no gas has been removed. Detailed reporting instructions are set out in *Bulletin 2006-42: Gas Removal Data System Compliance Process*, available on the ERCB Web site www.ercb.ca. Questions on reporting may be directed to the ERCB Economics Group at 403-297-5836.

ERCB Energy Resources Conservation Board

Short-Term Ethane Removal Application

For permit to remove ethane from Alberta in volumes less than 3 billion cubic metres (m^3) and for a term of not more than 2 years

This application is made under Section 2 of the *Gas Resources Preservation Act*.
Use this form for new permits and amendments of existing permits.

Remember to answer all questions and to add attachments if the space provided is inadequate. The ERCB reserves the right to require an applicant to furnish additional information as it deems necessary to complete or supplement the application.

1. Request is for ☐ New Permit
   ☐ Amendment to Permit No. ____________________

2. ☐ Change of permit holder (amendment of permit):
   Existing permit holder ____________________
   Proposed permit holder ____________________
   ☐ The proposed permit holder agrees to assume and perform all of the obligations and duties of the existing permit holder under the permit.

3. Permit(s) No. to be rescinded (if applicable) ____________________

4. Total volume of ethane proposed for removal:
   Existing volume authorized (if applicable) (m^3) ____________________
   Proposed volume authorized (m^3) ____________________

5. Term of permit
   Existing term and commencement date (if applicable) ____________________
   ____
   Proposed term and commencement date ____________________
   ____

(continued)

6. Name of proposed market(s) and location and type of end-use customer(s) to be served under the permit.

7. Are arrangements in place for transporting the applied-for ethane from the Alberta receipt point(s) to the intended end-use customer(s)?

☐ Yes ☐ No

If No, describe the transportation arrangements involved, including comments on when it is anticipated that any new facilities to be built would be completed.

8. List the name and location (Legal Subdivision-Section-Township-Range, Meridian) of the facilities from which the ethane will be obtained.

Reporting Requirements Associated with an Ethane Removal Permit

A monthly ethane removal permit statement must be completed for each permit and filed electronically with the ERCB by midnight on the 28th day of the month following the data month. The data month is the month when the ethane is delivered. If the 28th is not a business day, the deadline falls on the next business day. The form must be completed and filed for each permit even if no ethane has been removed. Detailed reporting instructions are set out in *Bulletin 2006-42: Gas Removal Data System Compliance Process*, available on the ERCB Web site www.ercb.ca. Questions on reporting may be directed to the ERCB Economics Department at 403-297-5836.

Appendix H

Gas Reserve Data Sheet

ERCB Energy Resources Conservation Board

DATE YR/MO/DAY

GAS VOLUMES AT 101.325 kPa AND 15°C

SUBMITTED BY

FIELD

POOL

ZONE

TOP OF PAY K.B. S.L.

POOL MEAN K.B.

TYPE WELL (LOCATION) W

BASE OF GAS PAY K.B. S.L.

FORMATION DEPTH S.L.

TYPE OF RESERVE
☐ ASSOCIATED
☐ NONASSOCIATED
☐ SOLUTION

AVERAGE POROSITY SOURCE

CUTOFFS POROSITY SOURCE

PERMEABILITY mD

GAS SATURATION (Sg) = 1 - (S_W + S_O)

S_W SOURCE

S_O SOURCE

INITIAL RESERVOIR PRESSURE, P_i SOURCE

RESERVOIR TEMPERATURE SOURCE

Z P_r SOURCE

T_r

GAS ANALYSIS P_c, kPa Tc, K

P_c', kPa Tc', K

RELATIVE DENSITY SOURCE

RESERVOIR CONSTANT $(m^3/m^3) = Ø \times Sg \times \frac{Pi}{101.325} \times \frac{288.15}{T} \times \frac{1}{Z}$

RECOVERY FACTOR SOURCE

SURFACE LOSS FACTOR SOURCE

RAW GAS COMPOSITION IN MOLE FRACTIONS

N_2	CO_2	H_2S	H_2	H_e	C_1	C_2	C_3	IC_4	nC_4

C_5	C_6	C_7+

SOURCE

GROSS HEATING VALUE OF MARKETABLE GAS, MJ/m^3

SOURCE

RESERVE ESTIMATE - INITIAL CONDITIONS

	PROVEN	PROBABLE
G/W, metres SL		
G/O, metres SL		
AREA, hectares		
h, metres		
ROCK VOLUME, $10^4 m^3$		
Ø, fraction		
GAS SAT, fraction		
P_i, k Pa		
T, K		
Z		
RESERVOIR CONSTANT, m^3/m^3		
IGIP, $10^6 m^3$		
RECOVERY FACTOR, fraction		
PRODUCIBLE, $10^6 m^3$		
SURFACE LOSS FACTOR, fraction		
MARKETABLE, $10^6 m^3$		
INITIAL ESTABLISHED MARKETABLE, $10^6 m^3$		
MARKETABLE GAS PRODUCED, $10^6 m^3$		
REMAINING ESTABLISHED MARKETABLE, $10^6 m^3$		
REMAINING ESTABLISHED MARKETABLE UNDER CONTRACT, $10^6 m^3$		
EFFECTIVE DATE, YR/MO/DAY		

– O	STOIP, $10^3 m^3$	
	GOR, m^3/m^3	
	GIP, $10^6 m^3$	
	RECOVERY FACTOR, fraction	
	PRODUCIBLE, $10^6 m^3$	
	SURFACE LOSS FACTOR, fraction	
	MARKETABLE, $10^6 m^3$	
	MARKETABLE GAS PRODUCED, $10^6 m^3$	
	REMAINING ESTABLISHED MARKETABLE, $10^6 m^3$	
	EFFECTIVE DATE YR/MO/DAY	

STOIP, $10^3 m^3 = 10AhØ\,(1-Sw)\,\frac{1}{B_{oi}}$

GOR SOURCE

$1/B_{oi}$ SOURCE

STOIP = STOCK TANK OIL IN PLACE

GOR = INITIAL DISSOLVED GAS-OIL RATIO

ADDITIONAL COMMENTS

EG-31(b) 2009-07

Energy Resources Conservation Board 640 - 5 Avenue SW Calgary, Alberta Canada T2P 3G4

Appendix I

Spacing Application Forms

New Spacing Application

Rescind Spacing Application

Change in Approval Holder Spacing Application

Print | Save | Sched 1 | Well Productivity | Close | Help

ERCB Energy Resources Conservation Board

Directive 065

New Spacing Application

DAY-MONTH-YEAR

99 - AAA – 9999

APPLICANT'S FILE NUMBER

The applicant certifies that the information provided here and in all supporting documentation is correct and in accordance with all regulatory requirements or as directed by the Energy Resources Conservation Board.

Submission Status

Submission Id

Creation Date

Primary Applicant

Substance Type

1. NOTIFICATION REQUIREMENTS

Help

1. Were *Directive 065* notification templates used?	YES ○	NO ○
2. Have all parties been notified in accordance with *Directive 065*?	YES ○	NO ○
3. What was the mailing date of the last notification letter sent?		
4. Are there any outstanding objections or concerns?	YES ○	NO ○
5. Is the application consistent with the details in the notification?	YES ○	NO ○

2. APPLICATION TYPE

Help

Spacing Application Type		Description
○ Holding or Unit	○ Holding	
	○ Unit Unit Name	
○ Special Drilling Spacing Unit (DSU)	○ Reduced DSU	
	○ Change in Target Area	
	○ Fractional Tract of Land	

3. AREA OF APPLICATION (maximum of 36 sections)

Help

View Map

Holding 1

LSD	Sec	Twp	Rge	Mer
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9

Holding 2

LSD	Sec	Twp	Rge	Mer
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9

Holding 3

LSD	Sec	Twp	Rge	Mer
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9

Unit

LSD	Sec	Twp	Rge	Mer
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9

Special DSU

LSD	Sec	Twp	Rge	Mer
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9

Formations

Formation 1
Formation 2
Formation 3

Field and Pools

Field: Field

Pool 1
Pool 2
Pool 3

4. APPLICATION DETAILS

Help

1. What is the source of the production? ☐
2. As defined by Schedule 13 of the *OGCR*, what area of the province is the application in? AREA1 ○ AREA2 ○

5. HOLDINGS OR UNITS

Help

Section 5 is not required for Special Drilling Spacing Unit (DSU) applications.

1. Does your area of application include entire DSUs? YES ○ NO ○
2. Does each applied-for holding have common ownership at the lessor and lessee levels? YES ○ NO ○
3. Is each applied-for holding/unit adjacent to a previously approved area for the same formation(s)/pool(s)? YES ○ NO ○
4. Does every DSU in each applied-for holding/unit have an adjacent DSU with production data? YES ○ NO ○
5. Is any part of each applied-for holding/unit within 3 standard DSUs of a previously approved area for the same formation(s)/pool(s)? YES ○ NO ○
6. Is the proposed well density less than or equal to the well density in the previously approved area? YES ○ NO ○
7. Does each proposed holding/unit contain production data in the applied-for formation(s)/pool(s)? YES ○ NO ○
8. Is the density of the oil 920 kilograms per cubic metre (kg/m^3) or greater at 15 degrees C? YES ○ NO ○
9. Enter the proposed well density.

Proposed Well Density

Number of Wells

Per Pool per Area

10. The standard buffer zone distance and orientation for this area of the province is:

10a. Do you want to proceed with the standard buffer zone distance and orientation? YES ○ NO ○

10b. If NO, enter the buffer zone distance. (m)

10c. Enter the buffer orientation. NORTH ☐ SOUTH ☐ EAST ☐ WEST ☐

11. Are you requesting an interwell distance? YES ○ NO ○

11a. If YES, enter the interwell distance. (m)

6. WELL EXEMPTIONS

Help

Section 6 is not required for Special Drilling Spacing Unit (DSU) applications.

1. Are any well exemptions requested? YES ○ NO ○

List of Exempted Wells

Location						Coordinates				Exempt From	Reason for Exemption
LE	LSD	Sec	Twp	Rge	Mer	N/S Distance	N/S Code	E/W Distance	E/W Code		

Add Well | Delete Well

7. SPECIAL DRILLING SPACING UNITS (DSUs)

Help

Section 7 is not required for Holding or Unit applications.

1. Does your area of application include entire DSUs? YES ○ NO ○
2. Are you applying on behalf of all working interest owners within the area of application? YES ○ NO ○
3. Are you reducing the size of the current DSU? YES ○ NO ○
4. Is each applied-for contiguous area of application adjacent to a previously approved area for the same formation(s)/pool(s)? YES ○ NO ○
5. Does every DSU in each applied-for contiguous area of application have an adjacent DSU with production data? YES ○ NO ○
6. Is any part of each contiguous area of application within 3 standard DSUs of a previous approval in the applied-for formation(s)/pool(s)? YES ○ NO ○
7. Does each contiguous area of application contain production data in the applied-for formation(s)/pool(s)? YES ○ NO ○
8. Is the proposed DSU size greater than or equal to the previously approved area? YES ○ NO ○
9. Are you applying for a standalone DSU? YES ○ NO ○
10. Enter the area of the fractional tract of land in hectares. Ha
11. Is there common ownership between your tract of land and an adjacent DSU? YES ○ NO ○
12. Enter the DSU size.
13. Enter the DSU orientation.

14. The standard target area locations for the requested DSU size are based on Section 4.030 of the *OGCR*.

15. Do you want to proceed with the standard target area in accordance with Section 4.030 of the *OGCR*? YES ○ NO ○

16. If NO, enter the proposed target area description.

If you have any questions or comments, please contact the EAS Administrator.

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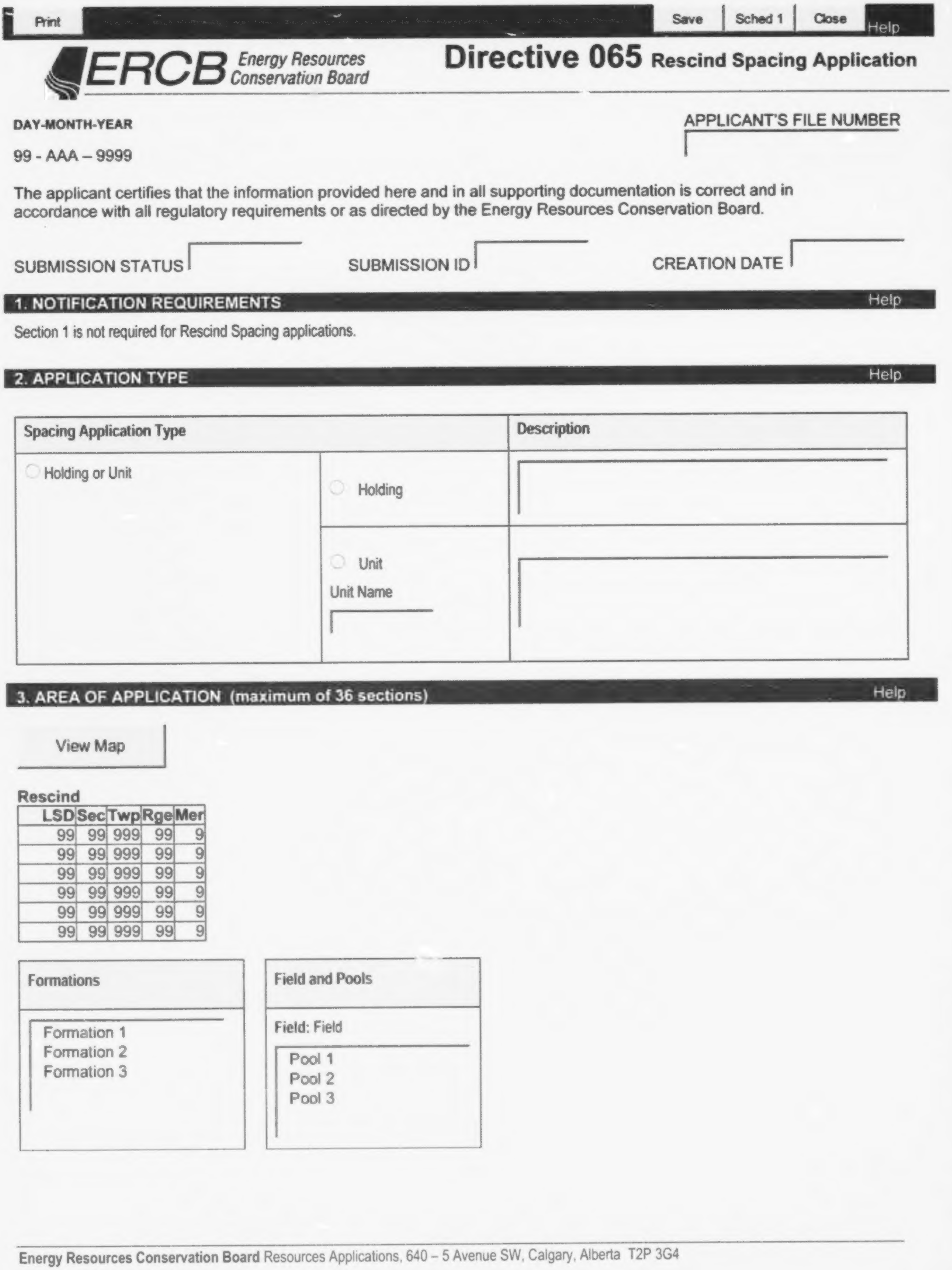

ERCB Energy Resources Conservation Board

Directive 065 Rescind Spacing Application

DAY-MONTH-YEAR

99 - AAA – 9999

APPLICANT'S FILE NUMBER

The applicant certifies that the information provided here and in all supporting documentation is correct and in accordance with all regulatory requirements or as directed by the Energy Resources Conservation Board.

SUBMISSION STATUS

SUBMISSION ID

CREATION DATE

1. NOTIFICATION REQUIREMENTS

Section 1 is not required for Rescind Spacing applications.

2. APPLICATION TYPE

Spacing Application Type		Description
○ Holding or Unit	○ Holding	
	○ Unit Unit Name	

3. AREA OF APPLICATION (maximum of 36 sections)

Rescind

LSD	Sec	Twp	Rge	Mer
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9

Formations

Formation 1
Formation 2
Formation 3

Field and Pools

Field: Field

Pool 1
Pool 2
Pool 3

Energy Resources Conservation Board Resources Applications, 640 – 5 Avenue SW, Calgary, Alberta T2P 3G4

4. APPLICATION DETAILS
Help

1. What is the source of production? .... [▾]

2. As defined by Schedule 13 of the *OGCR*, what area of the province is the application in? .... AREA1 ○ AREA2 ○

5. HOLDINGS OR UNITS
Help

1. Does your area of application include entire DSUs? .... YES ○ NO ○

2. Enter the well density to be rescinded.

Rescinded Well Density

Number of Wells

[ ]

Per Pool per Area

[▾]

3. Enter the buffer zone distance to be rescinded. [ ] (m)

3a. Enter the buffer orientation to be rescinded. NORTH ☐ SOUTH ☐ EAST ☐ WEST ☐

4. Is there an interwell distance to be rescinded? YES ○ NO ○

4a. If yes, enter the interwell distance to be rescinded. .... [ ] (m)

6. WELL EXEMPTIONS
Help

Section 6 is not required for Rescind Spacing applications.

7. SPECIAL DRILLING SPACING UNITS (DSUs)
Help

Section 7 is not required for Rescind Spacing applications.

If you have any questions or comments, please contact the EAS Administrator.

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Print | Save | Sched 1 | Close | Help

ERCB *Energy Resources Conservation Board*

Directive 065

Change in Approval Holder Spacing Application

Calgary Office 640–5 Avenue SW Calgary, Alberta Canada T2P 3G4 Tel 403 297-8311 Fax 403 297-7336 www.ercb.ca

DAY-MONTH-YEAR

99 - AAA – 9999

APPLICANT'S FILE NUMBER

The applicant certifies that the information provided here and in all supporting documentation is correct and in accordance with all regulatory requirements or as directed by the Energy Resources Conservation Board.

SUBMISSION STATUS

SUBMISSION ID

CREATION DATE

1. NOTIFICATION REQUIREMENTS

Help

Section 1 is not required for Change in Approval Holder Spacing applications.

2. APPLICATION TYPE

Help

Spacing Application Type		Description
○ Holding or Unit	○ Holding	
	○ Unit Unit Name	

3. AREA OF APPLICATION (maximum of 36 sections)

Help

View Map

Holding 1

LSD	Sec	Twp	Rge	Mer
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9

Holding 2

LSD	Sec	Twp	Rge	Mer
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9

Holding 3

LSD	Sec	Twp	Rge	Mer
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9

Unit

LSD	Sec	Twp	Rge	Mer
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9
99	99	999	99	9

Formations
Formation 1 Formation 2 Formation 3

Field and Pools
Field: Field
Pool 1 Pool 2 Pool 3

4. APPLICATION DETAILS

Help

1. What is the source of production? .... ▾

5. HOLDINGS OR UNITS

Help

1. Does each applied-for holding have common ownership at the lessor and lessee levels? .... YES ○ NO ○

2. Enter the well density of the holdings where the approval holder is to change.

Well Density
Number of Wells
Per Pool per Area
▾

3. Enter the buffer zone distance of the holdings where the approval holder is to change. (m)

3a. Enter the buffer orientation of the holdings where the approval holder is to change. NORTH ☐ SOUTH ☐ EAST ☐ WEST ☐

4. Do the holdings where the approval holder is to change have an interwell distance? YES ○ NO ○

4a. If yes, enter the interwell distance of the holdings where the approval holder is to change. .... (m)

6. WELL EXEMPTIONS

Help

Section 6 is not required for Change in Approval Holder applications.

7. SPECIAL DRILLING SPACING UNITS (DSUs)

Help

Section 7 is not required for Change in Approval Holder applications.

If you have any questions or comments, please contact the EAS Administrator.

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Appendix J

Special Well Spacing Notification Templates

Leased Freehold Notification Letter

Lessees and Unleased Freehold Notification Letter

Crown Lessor Notification Letter

Leased Freehold Notification Letter

[Date]

Dear [Sir/Madam]:

[APPLICANT NAME]
[SPECIAL [GAS/OIL] WELL SPACING]
[FIELD (s)]
[FORMATION(s)/POOL(s)]
[DLS LAND DESCRIPTION]

[Applicant/Consultant on behalf of Applicant] will be applying to the Energy Resources Conservation Board (ERCB) under [section] of the *Oil and Gas Conservation Act* [and/or] [section] of the *Oil and Gas Conservation Regulations* to change the subsurface well spacing for the production of [gas/oil] from the [formation(s)/pool(s)] in the noted lands [list lands in the above title and/or provide attachment/map].

Records indicate that you are a Freehold mineral owner in [DLS land description] and your minerals are leased to [Company]. ERCB *Directive 065: Resources Applications for Conventional Oil and Gas Reservoirs* requires that all Freehold mineral owners within the applied-for formation(s) in the area of application and one (1) drilling spacing unit (DSU) surrounding the area of application whose rights are leased receive notification of the subject application. The purpose of this notification is to provide you with information regarding potential development and to support ongoing dialogue between you and the lessee of your minerals.

[Applicant/Consultant on behalf of Applicant] proposes that within the area of application the existing [gas/oil] well spacing be changed from [the current spacing in place] to the following:

Example: Holding

Establish a holding constituting [DLS land description] for the production of [gas/oil] from the [applied-for formation(s)/pool(s)] subject to:

A producing well will be at least [X] metres from the boundaries of the holding.
There will be a maximum of [X] producing wells per pool per [DSU size].
A producing well will be at least [X] metres from other wells producing from the same pool. (Only applicable if requesting an interwell distance.)
The following well UWIs [XX/XX-XX-XXX-XX-WX] will be exempt from the [buffer zone and/or interwell distance].

Example: Reduced Well Spacing

Establish drilling spacing units of [DSU size] [and if applicable orientation], with the target area being [target area(s)] for the production of [oil/gas] in the [applied-for formation(s)/pool(s)] in [DLS land description].

[Brief Discussion of Reason for Application]

The lessee of your minerals has also been notified of this application. Therefore, if you have any questions regarding the effect of this application on your interests, please contact your lessee. If discussions between you and your lessee do not address your concerns, please clearly state your concerns in writing to the undersigned at [applicant's address] or by fax or e-mail within 15 business days from the date of this letter. Your concerns will be included as a submission to the application when filed with the ERCB.

OR

As [Company] is the lessee of your offsetting minerals in [DLS land description], should you have questions regarding the effect of this application on your minerals, please contact [applicant contact person and phone number]; you may also send your concerns in writing to [applicant's address] or by fax or e-mail within 15 business days from the date of this letter. If discussions do not address your concerns, they will then be included as a submission to the application when filed with the ERCB.

Under Section 13 of the *Energy Resources Conservation Board Rules of Practice*, all documents filed with the ERCB in connection to an application must be placed on the public record, which may be accessible on the Internet. As such, you should not include any confidential or sensitive personal information (e.g., health issues, financial position, family issues) in documents submitted to us or the ERCB that you do not want to appear on the public record. However, any party may, before filing the document, file a request to the ERCB for confidentiality of documents under Subsection 13(2). The Board may grant a request for confidentiality on any terms it considers appropriate, subject to the *Freedom of Information and Protection Act*.

After the application has been registered with the ERCB, copies may be obtained by contacting the undersigned or may be viewed electronically by accessing IAR Query through Quick Links on the ERCB Web site at www.ercb.ca.

Any questions regarding the ERCB process should be directed to the ERCB Customer Contact Centre at 403-297-8311.

Yours truly,

[Applicant]

Lessees and Unleased Freehold Notification Letter

[Date]

Dear [Sir/Madam]:

[APPLICANT NAME]
[SPECIAL [GAS/OIL] WELL SPACING]
[FIELD (s)]
[FORMATION(s)/POOL(s)]
[DLS LAND DESCRIPTION]

[Applicant/Consultant on behalf of Applicant] will be applying to the Energy Resources Conservation Board (ERCB) under [section] of the *Oil and Gas Conservation Act* [and/or] [section] of the *Oil and Gas Conservation Regulations* to change the subsurface well spacing for the production of [gas/oil] from the [formation(s)/pool(s)] in the noted lands [list lands in the above title and/or provide attachment/map]. ERCB *Directive 065: Resources Applications for Conventional Oil and Gas Reservoirs* requires that all mineral owners within the applied-for formation in the area of application and one (1) drilling spacing unit (DSU) surrounding the area of application receive notification of a well spacing application.

[Applicant/Consultant on behalf of Applicant] proposes that within the area of application, the existing [gas/oil] well spacing be changed from [the current spacing in place] to the following:

Example: Holding

Establish a holding constituting [DLS land description] for the production of [gas/oil] from the [applied-for formation(s)/pool(s)] subject to:

A producing well will be at least [X] metres from the boundaries of the holding.
There will be a maximum of [X] producing wells per pool per [DSU size].
A producing well will be at least [X] metres from other wells producing from the same pool. (Only applicable if requesting an interwell distance.)
The following well UWIs [XX/XX-XX-XXX-XX-WX] will be exempt from the [buffer zone and/or interwell distance].

Example: Reduced Well Spacing

Establish drilling spacing units of [DSU size] [and if applicable orientation], with the target area being [target area(s)] for the production of [oil/gas] in the [applied-for formation(s)/pool(s)] in [DLS land description].

[Brief Discussion of Reason for Application]

Any concerns and/or questions regarding this application are to be directed to [applicant contact person and phone number]. You may also send your concerns in writing to [applicant's address] or by fax or e-mail within 15 working days from the date of this letter. [Applicant] will contact you to discuss your concerns. Should your concerns remain unresolved, they will be included as a submission to the application when filed with the ERCB.

Under Section 13 of the *Energy Resources Conservation Board Rules of Practice*, all documents filed with the ERCB in connection to an application must be placed on the public record, which may be accessible on the Internet. As such, you should not include any confidential or sensitive personal information (e.g., health issues, financial position, family issues) in documents submitted to us or the ERCB that you do not want to appear on the public record. However, any party may, before filing the document, file a request to the ERCB for confidentiality of documents under Subsection 13(2). The Board may grant a request for confidentiality on any terms it considers appropriate, subject to the *Freedom of Information and Protection Act*.

In the absence of a response on or before [date—at least 15 working days from the mailing date of this letter], we will proceed to file the application with the ERCB.

After the application has been registered with the ERCB, copies may be obtained by contacting the undersigned or may be viewed electronically by accessing IAR Query through Quick Links on the ERCB Web site at www.ercb.ca.

Any questions regarding the ERCB process should be directed to the ERCB Customer Contact Centre at 403-297-8311.

Yours truly,

[Applicant]

Crown Lessor Notification Letter

[Date]

Dear [Sir/Madam]:

[APPLICANT NAME]
[SPECIAL [GAS/OIL] WELL SPACING]
[FIELD (s)]
[FORMATION(s)/POOL(s)]
[DLS LAND DESCRIPTION]

[Applicant/Consultant on behalf of Applicant] will be applying to the Energy Resources Conservation Board (ERCB) under [section] of the *Oil and Gas Conservation Regulations* to change the subsurface well spacing for the production of [gas/oil] from the [formation(s)/pool(s)] in the noted lands [list lands in the above title and/or provide attachment/map]. ERCB *Directive 065: Resources Applications for Conventional Oil and Gas Reservoirs* requires that Alberta Energy (the Crown) receive notification of all well spacing applications proposing to change the size of a drilling spacing unit (DSU) or to establish a fractional tract of land as a DSU if the mineral rights in the applied-for formation(s)/pool(s) are either leased or unleased within the area of application and 1 DSU surrounding the area of application.

[Applicant/Consultant on behalf of Applicant] proposes that within the area of application, the existing [gas/oil] well spacing be changed from [the current spacing in place] to the following:

Example: Change the DSU Size

Establish drilling spacing units of [DSU size] [and if applicable orientation], with the target area being [target area(s)] for the production of [oil/gas] in the [applied-for formation(s)/pool(s)] in [DLS land description].

Example: Fractional Tract of Land

Establish a fractional tract of land as a Special DSU with the target area being [target area(s)] for the production of [oil/gas] in the [applied-for formation(s)/pool(s)] in [DLS land description].

Any concerns and/or questions regarding this application are to be directed to [applicant contact person and phone number]. You may also send your concerns in writing to [applicant's address] or by fax or e-mail within 15 working days from the date of this letter. [Applicant] will contact you to discuss your concerns. Should your concerns remain unresolved, they will be included as a submission to the application when filed with the ERCB.

Under Section 13 of the *Energy Resources Conservation Board Rules of Practice*, all documents filed with the ERCB in connection to an application must be placed on the public record, which may be accessible on the Internet. As such, you should not include any confidential or sensitive personal information (e.g., health issues, financial position, family issues) in documents submitted to us or the ERCB that you do not want to appear on the public record. However, any party may, before filing the document, file a request to the ERCB for confidentiality of documents under Subsection 13(2). The Board may grant a request for confidentiality on any terms it considers appropriate, subject to the *Freedom of Information and Protection.*

In the absence of a response on or before [date—at least 15 working days from the mailing date of this letter], we will proceed to file the application with the ERCB.

After the application has been registered with the ERCB, copies may be obtained by contacting the undersigned or may be viewed electronically by accessing IAR Query through Quick Links on the ERCB Web site at www.ercb.ca.

Any questions regarding ERCB process should be directed to the ERCB Customer Contact Centre at 403-297-8311.

Yours truly,

[Applicant]

Appendix K

Special Well Spacing Attachment Examples

Lessor Map and Notification Area

Lessee Map and Notification Area

Mineral Rights Ownership and Notification List

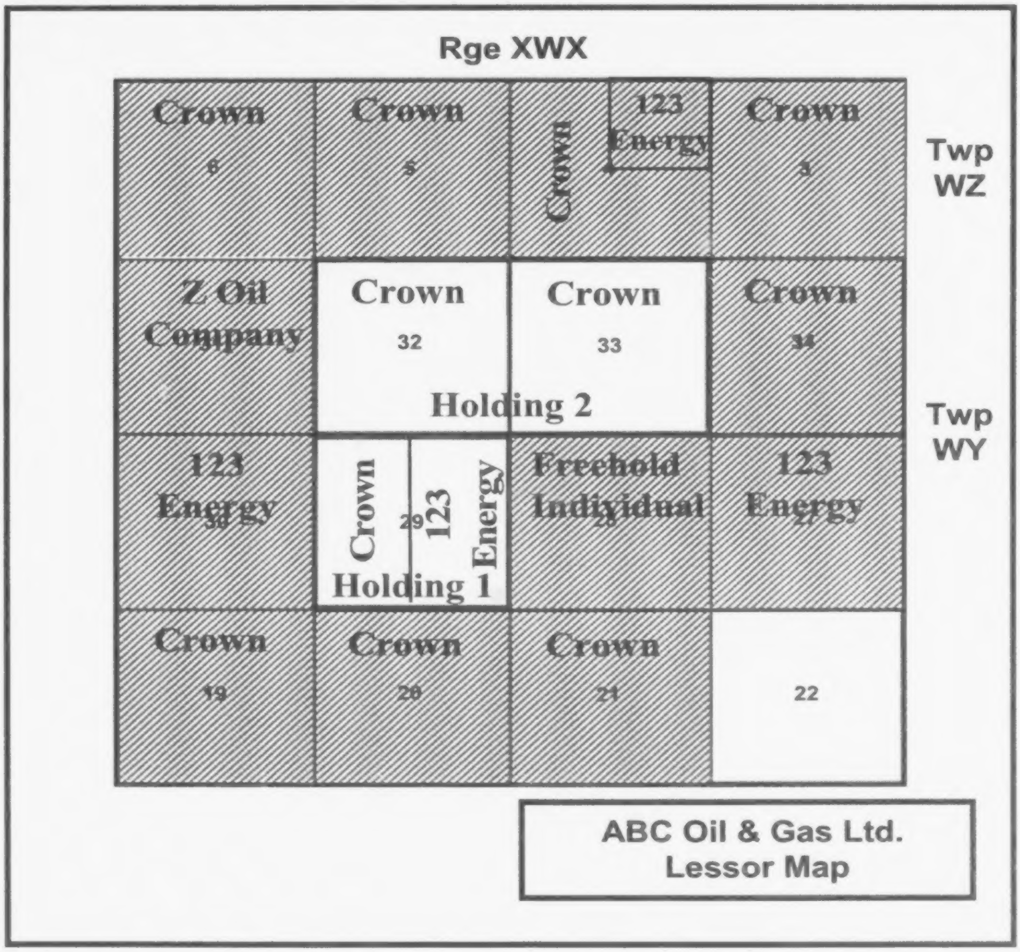
Lessor Map and Notification Area

Show only the lessors for the substance and formation(s)/pool(s) being applied for within the application area and one DSU around the application area. The application area must be clearly outlined on the map and the information must be accurate and shown on a map of sufficient scale to facilitate a quick review of the mineral ownership.

For areas with complex ownership, a map coded to a list of mineral owners may be used. Do not send title search documents.

In this map, the notification area includes Holding 1, Holding 2, and 1 DSU ▨ around the application area.

Example: Lessor Map for NG in the Rock Creek Formation


Rge XWX
Crown
6
Crown
5
Crown
4
123 Energy
Crown
3
Twp WZ
Z Oil Company
Crown
32
Crown
33
Holding 2
Crown
34
Twp WY
123 Energy
30
Crown
29
123 Energy
Holding 1
Freehold Individual
28
123 Energy
27
Crown
19
Crown
20
Crown
21
22
ABC Oil & Gas Ltd.
Lessor Map

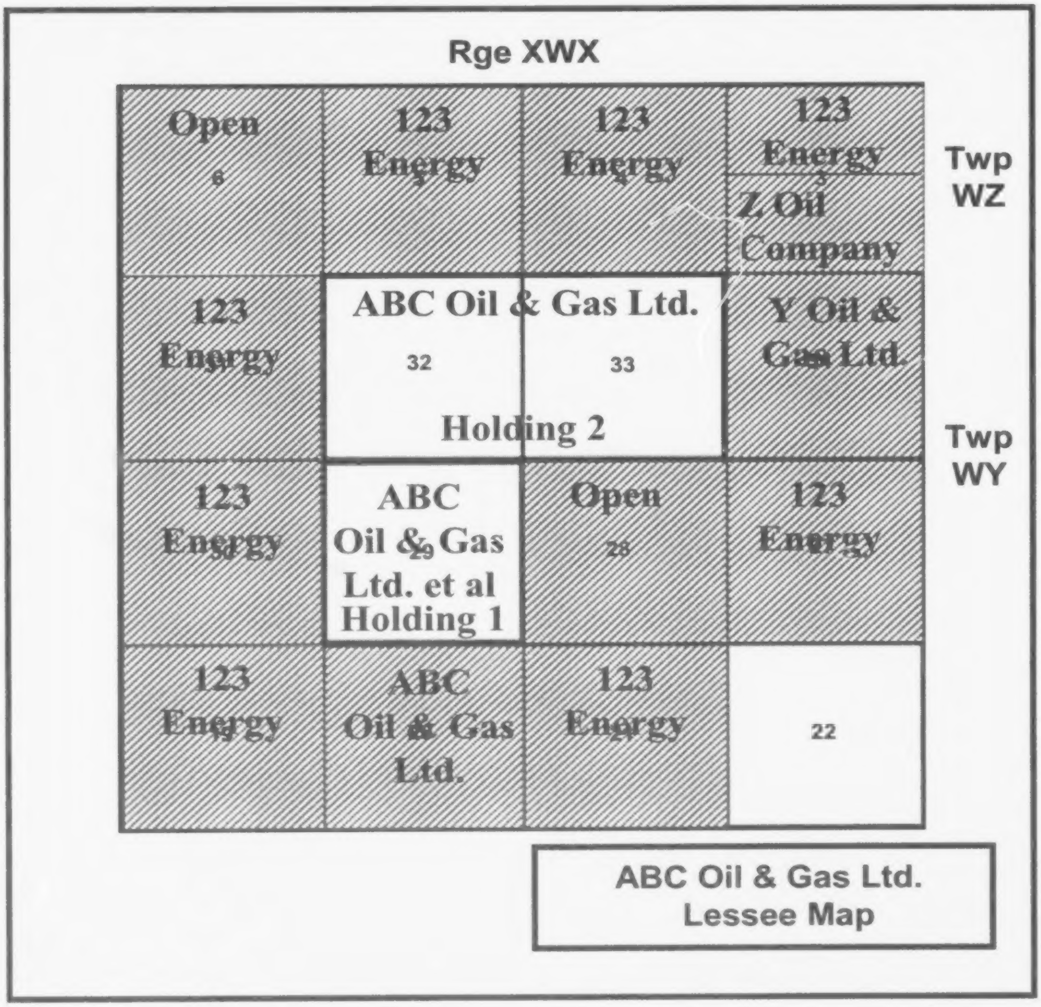
Lessee Map and Notification Area

Show only the lessees for the substance and formation(s)/pool(s) being applied for within the application area and one DSU around the application area. The application area must be clearly outlined on the map and the information must be accurate and shown on a map of sufficient scale to facilitate a quick review of the mineral ownership.

For areas with complex ownership, a map coded to a list of mineral owners may be used. Do not send title search documents.

In this map the notification areas are Holding 1, Holding 2, and 1 DSU ▨ around the application area.

Example: Lessee Map for NG in the Rock Creek Formation


Rge XWX
Twp WZ
Twp WY
Open
6
123 Energy
5
123 Energy
4
123 Energy
3
Z Oil Company
123 Energy
ABC Oil & Gas Ltd.
32
33
Holding 2
Y Oil & Gas Ltd.
123 Energy
ABC Oil & Gas Ltd. et al
29
Holding 1
Open
28
123 Energy
123 Energy
ABC Oil & Gas Ltd.
123 Energy
22
ABC Oil & Gas Ltd.
Lessee Map

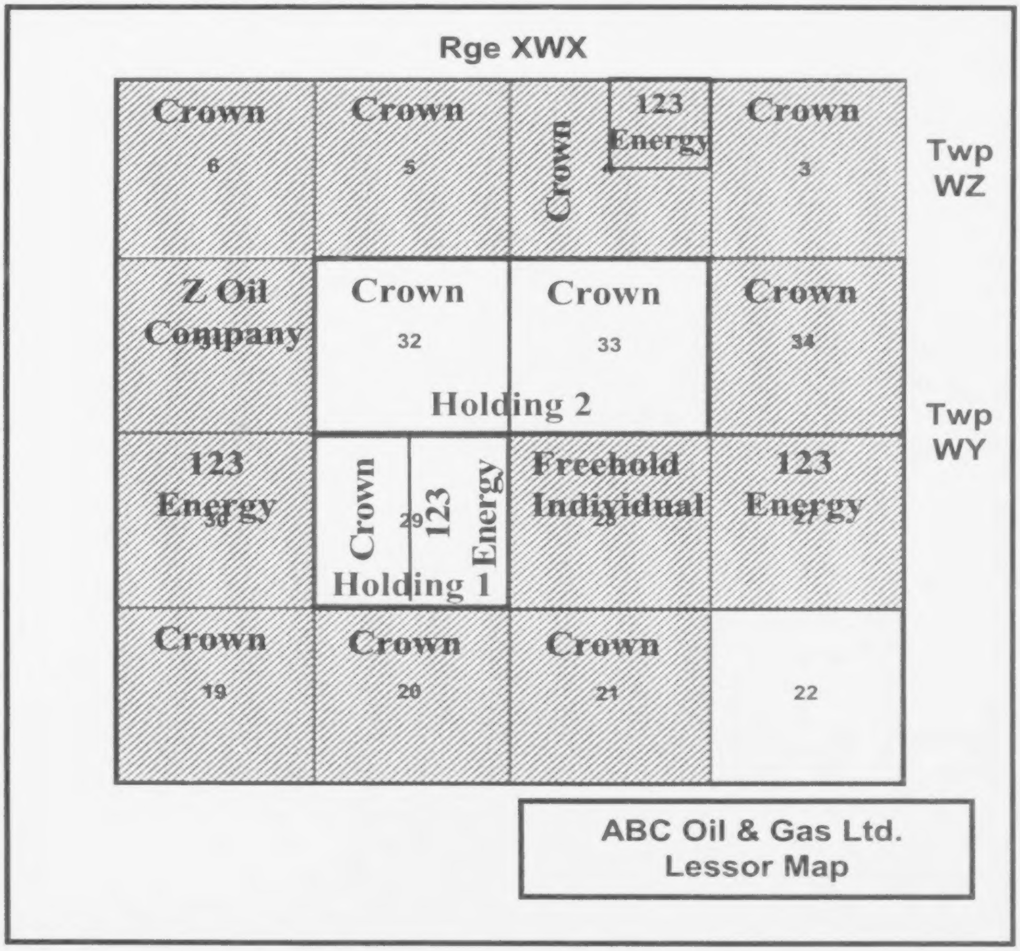
Lessor Map and Notification Area

Show only the lessors for the substance and formation(s)/pool(s) being applied for within the application area and one DSU around the application area. The application area must be clearly outlined on the map and the information must be accurate and shown on a map of sufficient scale to facilitate a quick review of the mineral ownership.

For areas with complex ownership, a map coded to a list of mineral owners may be used. Do not send title search documents.

In this map, the notification area includes Holding 1, Holding 2, and 1 DSU ▨ around the application area.

Example: Lessor Map for NG in the Rock Creek Formation


Rge XWX
Crown 6
Crown 5
Crown
123 Energy
Crown 3
Twp WZ
Z Oil Company 31
Crown 32
Crown 33
Holding 2
Crown 34
Twp WY
123 Energy 30
Crown
29
123 Energy
Holding 1
Freehold Individual 28
123 Energy 27
Crown 19
Crown 20
Crown 21
22
ABC Oil & Gas Ltd.
Lessor Map

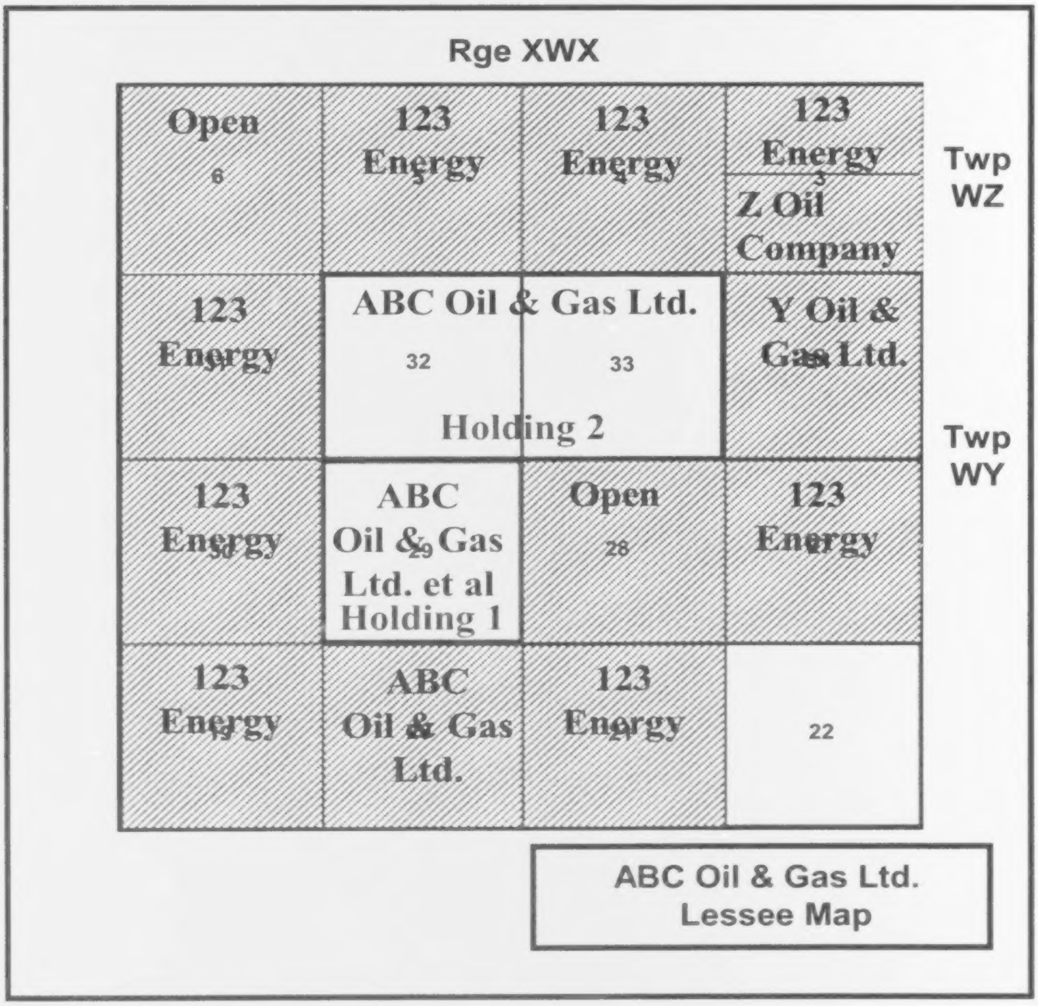
Lessee Map and Notification Area

Show only the lessees for the substance and formation(s)/pool(s) being applied for within the application area and one DSU around the application area. The application area must be clearly outlined on the map and the information must be accurate and shown on a map of sufficient scale to facilitate a quick review of the mineral ownership.

For areas with complex ownership, a map coded to a list of mineral owners may be used. Do not send title search documents.

In this map the notification areas are Holding 1, Holding 2, and 1 DSU ▨ around the application area.

Example: Lessee Map for NG in the Rock Creek Formation


Rge XWX
Open 6
123 Energy 5
123 Energy 4
123 Energy 3
Z Oil Company
Twp WZ
123 Energy 31
ABC Oil & Gas Ltd.
32
33
Holding 2
Y Oil & Gas Ltd. 34
Twp WY
123 Energy 30
ABC Oil & Gas Ltd. et al 29
Holding 1
Open 28
123 Energy 27
123 Energy 19
ABC Oil & Gas Ltd. 20
123 Energy 21
22
ABC Oil & Gas Ltd.
Lessee Map

Mineral Rights Ownership and Notification List

List all mineral rights owners who have oil, gas, and coal rights in the applied-for formation(s)/pool(s) and were notified of your application. The list must include the legal land description of each mineral owner, their working interest, and a description of their mineral right(s). (Addresses of mineral owners are not required.) This list is in addition to the lessor and lessee maps.

Mineral Rights Ownership and Notification List (Example for Rock Creek Formation)

AREA OF APPLICATION

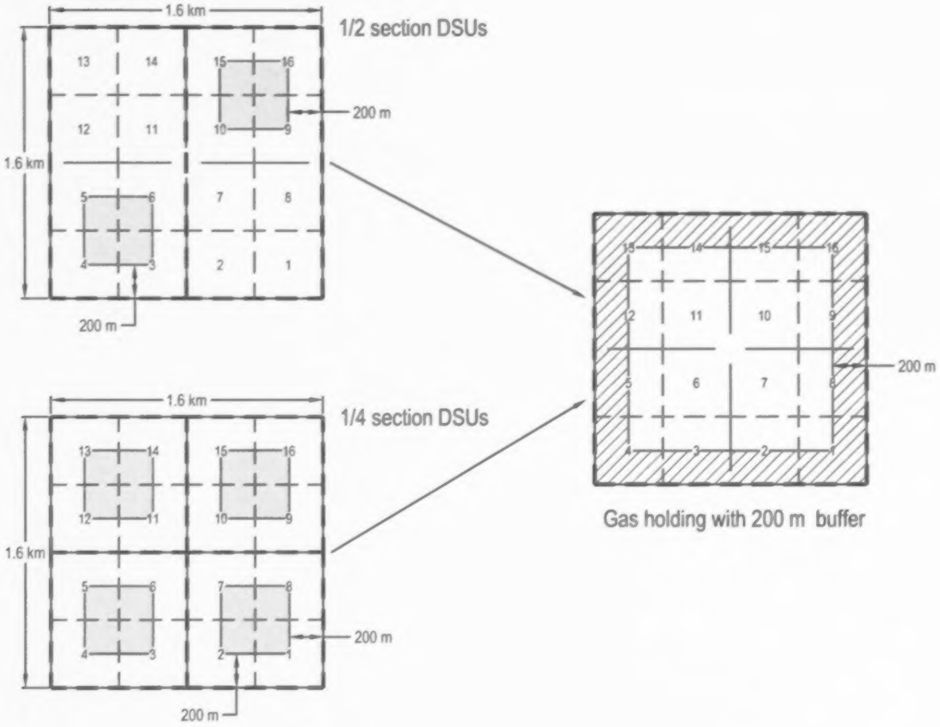
Location	Lessor	Lessee	Working Interest	Mineral Right(s)
HOLDING 1				
TwpWY-RgeX WX: Sec 29 E½	123 Energy	ABC Oil & Gas Ltd.	50%	P&NG surface to basement
		Z Oil Company	50%	P&NG surface to basement
TwpWY-RgeX WX: Sec 29 W½	Crown	ABC Oil & Gas Ltd.	50%	P&NG surface to basement
		Z Oil Company	50%	P&NG surface to basement
HOLDING 2				
TwpWY-RgeX WX: Sec 32	Crown	ABC Oil & Gas Ltd.	100%	P&NG surface to base Rock Creek
TwpWY-RgeX WX: Sec 33	Crown	ABC Oil & Gas Ltd.	100%	P&NG surface to base Rock Creek

1 DSU SURROUNDING AREA OF APPLICATION

Location	Lessor	Lessee	Working Interest	Mineral Right(s)
Twp WY-RgeX WX: Sec 19	Crown	123 Energy	100%	P&NG surface to basement
Twp WY-RgeX WX: Sec 20	Crown	ABC Oil & GasLtd.	100%	P&NG Rock Creek formation
Twp WY-RgeX WX: Sec 21	Crown	123 Energy	100%	P&NG surface to basement
Twp WY-RgeX WX: Sec 27	123 Energy	123 Energy	100%	P&NG surface to basement
Twp WY-RgeX WX: Sec 28	Freehold Individual	Open	100%	P&NG Rock Creek formation
Twp WY-RgeX WX: Sec 30	123 Energy	123 Energy	100%	P&NG surface to basement
Twp WY-RgeX WX: Sec 31	Z Oil Company	123 Energy	100%	P&NG surface to basement
Twp WY-RgeX WX: Sec 34	Crown	Y Oil & Gas Ltd.	100%	NG Rock Creek formation
Twp WY-RgeX WX: Sec 34	Crown	XYZ Oil	100%	Petroleum Rock Creek formation
Twp WZ-RgeX WX: Sec 3 N½	Crown	123 Energy	100%	P&NG surface to basement
Twp WZ-RgeX WX: Sec 3 S½	Crown	Z Oil Company	100%	P&NG surface to base Nordegg
Twp WZ-RgeX WX: Sec 4 S½, NW 1/4	Crown	123 Energy	100%	P&NG surface to basement
Twp WZ-RgeX WX: Sec 4 NE 1/4	123 Energy	123 Energy	100%	P&NG surface to basement
Twp WZ-RgeX WX: Sec 5	Crown	123 Energy	100%	P&NG surface to basement
Twp WZ-RgeX WX: Sec 6	Crown	Open	100%	Coal surface to basement
Twp WZ-RgeX WX: Sec 6	Crown	Open	100%	P&NG surface to basement

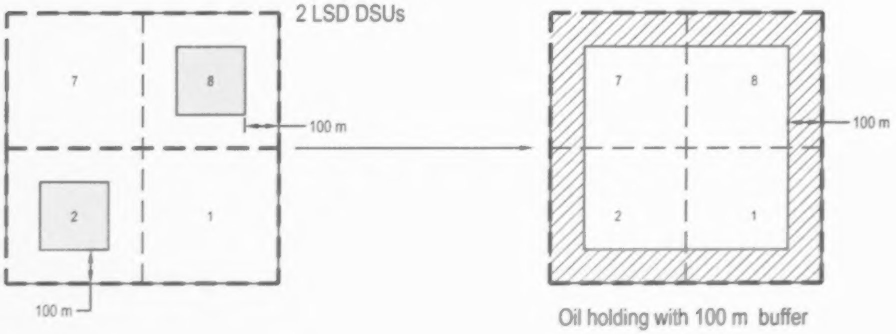
Appendix L Standard Buffer Zones

For Gas Production – Area 1


1.6 km
1/2 section DSUs
1.6 km
13
14
15
16
12
11
10
9
5
6
7
8
4
3
2
1
200 m
200 m
1/4 section DSUs
200 m
200 m
200 m

Gas holding with 200 m buffer

For Oil Production – Area 1


2 LSD DSUs
7
8
2
1
100 m
100 m
100 m

Oil holding with 100 m buffer

Legend

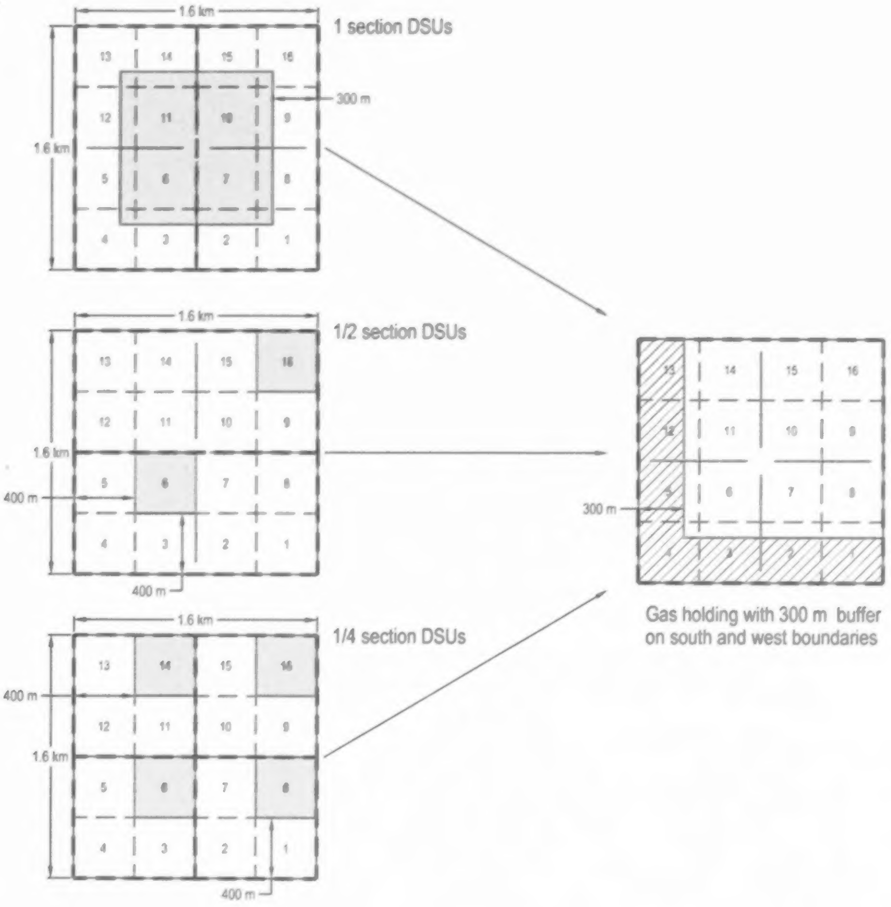
— — Boundary of drilling spacing unit (DSU)

▭ Standard target area for DSU

▨ Buffer zone for holding

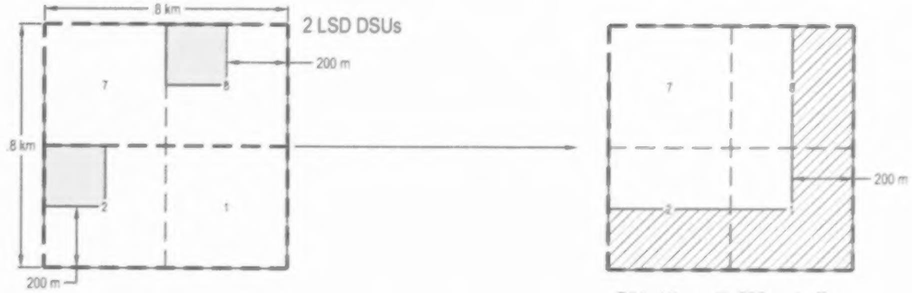
Standard buffers for holdings in Area 1 for well densities to 4 wells/pool/standard DSU

For Gas Production – Area 2


1.6 km
1 section DSUs
300 m
1/2 section DSUs
400 m
1/4 section DSUs
13
14
15
16
12
11
10
9
5
6
7
8
4
3
2
1

Gas holding with 300 m buffer on south and west boundaries

For Oil Production – Area 2


.8 km
2 LSD DSUs
200 m
7
8
2
1

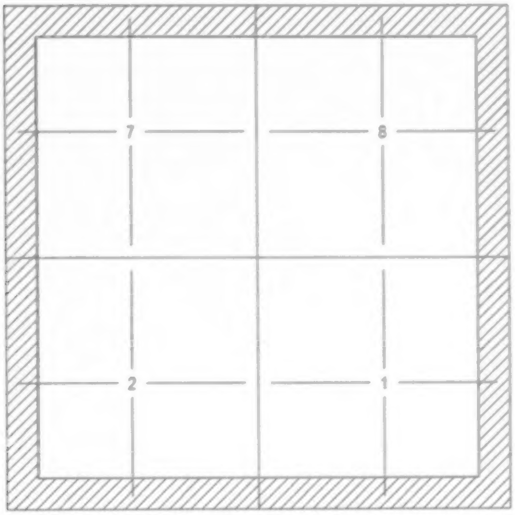
Oil holding with 200 m buffer on south and east boundaries

Legend

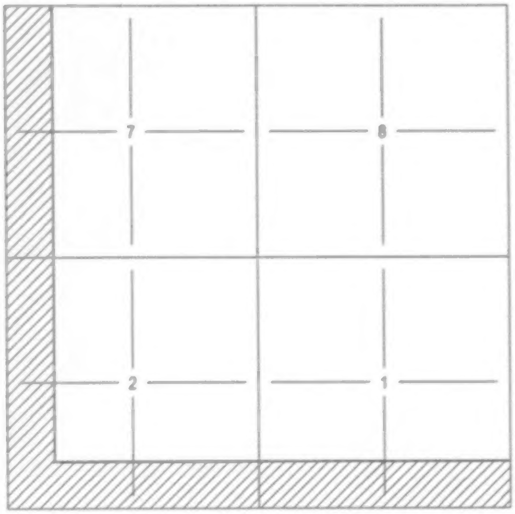
- – – Boundary of drilling spacing unit (DSU)
- ▭ Standard target area for DSU
- ▨ Buffer zone for holding

Standard buffers for holdings in Area 2 for well densities to 4 wells/pool/standard DSU

Buffer Zones for Gas Holdings

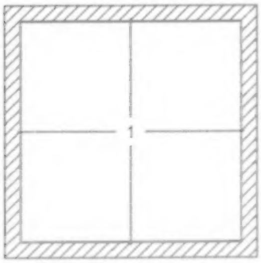


Area 1: Example of four section gas holding (four standard gas DSUs). Buffer is 200 m from sides of holding.

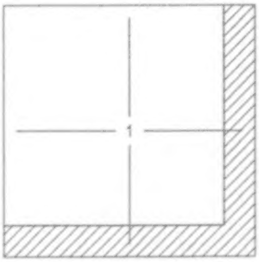


Area 2: Example of four section gas holding (four standard gas DSUs). Buffer is 300 m from south and west sides of holding.

Buffer Zone for Oil Holdings



Area 1: Example of an oil holding of four quarter sections (four standard oil DSUs). Buffer is 100 m from sides of holding.



Area 2: Example of an oil holding of four quarter sections (four standard oil DSUs). Buffer is 200 m from south and east sides of holding.

Examples of holdings with standard buffers